EA-90-01

ENVIRONMENTAL ASSESSMENT BOARD

Ontario

ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARINGS

VOLUME: 174

DATE: Tuesday, January 5, 1993

BEFORE:

HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

FARR & ASSOCIATES REPORTING INC.

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EA-90-01

ENVIRONMENTAL ASSESSMENT BOARD
ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARING

IN THE MATTER OF the Environmental Assessment Act, R.S.O. 1980, c. 140, as amended, and Regulations thereunder;

AND IN THE MATTER OF an undertaking by Ontario Hydro consisting of a program in respect of activities associated with meeting future electricity requirements in Ontario.

Held on the 5th Floor, 2200 Yonge Street, Toronto, Ontario, Tuesday, the 5th day of January, 1993, commencing at 9:00 a.m.

VOLUME 174

B E F O R E :

THE HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

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TIME NOTATIONS

---Upon commencing at 9:03 a.m.

THE REGISTRAR: Please come to order. This hearing is now in session. Be seated, please.

THE CHAIRMAN: The last exhibit number that was assigned before we adjourned to this date was 795. Exhibit 796 filed by the proponent is the subject matter of the hearing today.

Since that time there have been further exhibits filed by intervenors and they have been assigned numbers 797 to 936.

A list of the exhibits has been provided to the court reporters for inclusion into today's transcript. Some reports and witness statements filed yesterday have not yet been assigned numbers, and they will appear on tomorrow's list of new exhibits, which will be included in the transcript in the same fashion.

So I won't be reading in the exhibits. We would be here most of the morning if I did that.

Mr. Campbell?

MR. B. CAMPBELL: Thank you, Mr. Chairman.

As I believe everyone in this room will be aware and as is set out in the material filed as Exhibit 796 Ontario Hydro on December 17th gave notice of termination to Manitoba Hydro with respect to the

Manitoba contract, and as a result of that action being taken I can advise the Board today that approval is no longer being requested by Ontario Hydro for the requirement and rationale for additional transmission facilities to incorporate electricity purchased from Manitoba. Mr. Snelson in the course of his direct testimony this morning will be speaking briefly to that matter.

With that said, unless the Panel has any other matters which it would like me to address, I propose to call the evidence of the Panel which as requested of us is intended to address the circumstances in Ontario Hydro's planning as they have developed over the fall.

THE CHAIRMAN: So the approvals now being sought are for the hydraulic range; is that correct?

MR. B. CAMPBELL: That's correct, Mr. Chairman.

THE CHAIRMAN: And that has remained unchanged?

MR. B. CAMPBELL: That is correct.

THE CHAIRMAN: Before Mr. Campbell calls his evidence are there any intervenors wishing to make submissions?

Yes, Mr. Watson. We have your letter in

which you are concerned about the site-specific nature of some of the material in 796 and in which you propose a solution to that in the third last paragraph.

Have you seen the letter, Mr. Campbell?

MR. B. CAMPBELL: Yes, I have, Mr. Chairman.

THE CHAIRMAN: Does that solution seem satisfactory to you?

MR. B. CAMPBELL: I believe so.

Because of the nature of the work that has been undertaken at the Corporation with respect to this project it is virtually impossible for us to address them without naming the projects that are -- have in mind, but we do understand that site-specific approvals are not available to us in these proceedings.

THE CHAIRMAN: Is that satisfactory, Mr. Watson?

MR. H. WATSON: Thank you, Mr. Chairman.

MR. GREENSPOON: Well, sir, I hate to be a fly in the ointment, but I have a problem with -- well, that is no way to start off, but...

I think that he raises some interesting issues that apply across the board. I think this has now become a site-specific hearing. There is a CANDU 6 on a new site, there is a CANDU 6 on an old site.

So I think -- whether his solution is appropriate or not that is for you to decide. I just wish to point out to the Board that I think the issue he raises about hydraulic applies to everything. It applies to nuclear, the whole exhibit now is very site-specific, and I think that it is an interesting issue, what has this hearing turned into, and maybe that's --

THE CHAIRMAN: I suggest, Mr. Greenspoon, that that is a matter that is more appropriately dealt with on your motion.

MR. GREENSPOON: Okay. I don't want to argue my motion now.

THE CHAIRMAN: Thank you. Mr. Poch?

MR. D. POCH: Mr. Chairman, just from a surfeit of caution, I was just going to say that in determining what to do with this evidence, really wrestling with some of the very issues which are woven into the motion, and, as you will be aware, we are arguing that the only basis for any approval now would be by reference to site-specific considerations.

So I would just ask the Board if I could request it that today's decision with respect to this evidence be dealt with in a fashion which is without prejudice to the matters before the Board in the

motion, that's all.

THE CHAIRMAN: The issue that the three have been raised is certainly a matter that will be entertained when the Northwatch motion comes up.

MR. D. POCH: Thank you, Mr. Chairman. That is satisfactory.

THE CHAIRMAN: Mr. Campbell? I think all the witnesses are familiar. So they have all been previously sworn in these proceedings?

MR. B. CAMPBELL: Yes, Mr. Chairman, and I have advised them that they remain under oath in these proceedings.

Just for those who haven't caught title changes along the path of this hearing I will perhaps remind the Panel that Mr. Snelson is Manager, Demand/Supply Strategy Integration, manager of that department. Mr. Dalziel reports to Mr. Snelson, is a member of that department's analytic team. Mr. Shalaby since you last saw him has moved from Mr. Snelson's department. And, Mr. Shalaby, perhaps you could give us your new title? [Laughter.]

MR. SHALABY: It is: "Manager of Energy Management, Planning and Policy Department".

MR. CAMPBELL: And that, as I understand it, Mr. Shalaby, in the Energy Management Branch?

MR. SHALABY: It is, yes.

MR. CAMPBELL: And Mr. Burke remains Manager of Load Forecasts.

I have overheads that will be referred to by the panel, and perhaps I could ask these to be distributed, and I will provide copies for the Board.

THE CHAIRMAN: Should we give these overheads an exhibit number?

MR. B. CAMPBELL: Yes, I believe they --

THE REGISTRAR: That will be 937, Mr. Chairman.

THE CHAIRMAN: 937?

THE REGISTRAR: 937, yes.

THE CHAIRMAN: Thank you.

---EXHIBIT NO. 937: Panel 11, Demand/Supply Plans, Overheads.

THE CHAIRMAN: Just to make it clear when everyone has got the chance to write it down, these overheads will be given exhibit No. 937.

AMIR SHALABY,
PAUL JONATHAN BURKE,
BRIAN PAUL WILLIAM DALZIEL,
JOHN KENNETH SNELSON; Previously Sworn.

DIRECT EXAMINATION BY MR. B. CAMPBELL:

Q. Mr. Snelson, I would like to start with you, please, and just ask you to very briefly

outline the influences that have shaped the demand/supply decisions since the DSP Update and the evidence given by Panel 10.

MR. SNELSON: A. I think there are two main influences affecting demand/supply decision-making since Panel 10.

The first one is to complete unfinished business from the Update, and you will recall that at the time of the Update and of Panel 10 we could tell you that we expected to have a surplus capacity and that we intended to manage it, but we did not have specific decisions on how to manage it; we had an illustrative set of assumptions which we talked about on Panel 10.

Through the rest of 1992 we have been through our business planning addressing how to make actual decisions about surplus management rather than illustrative decisions, and that is being done while considerations are being given to maintaining flexibility along with the same concept as the response portfolio that we discussed in Panel 10.

The second main influence or main thrust that has affected our decision making in this time period is to respond to intensifying external pressures. These are not new pressures, they are

pressures that we were experiencing at the time of the Update, and they are generally in the same direction as the pressures that we were experiencing at the time of the Update, but they have intensified. They are of greater intensity.

[9:14 a.m.]

Q. All right. Perhaps you could outline what these pressures are and how in general terms they have effected Hydro's planning considerations.

A. Well, part of the external pressures relate to the economic situation, and Mr. Burke in discussing the load forecasting will be discussing how the economy has continued to be slow, with lower inflation than had previously been forecast, and the lower level of economic activity has contributed to loads, actual loads being less than forecast, and also has contributed to reductions in the forecast of future loads, particularly over the next few years and extending out over about 10 years in total.

This has a number of consequences, it puts upward pressure on electricity rates and at the same time because of the recessionary economic situation, there is a reduced ability and a reduced willingness on the part of customers to accept higher rates. And so together the upward pressure on rates

and the reduced willingness to accept higher rates puts a financial squeeze on Ontario Hydro.

Q. All right. Dealing with both halves of that squeeze, if you will, can you comment on the various factors that are causing upward pressure on rates?

A. Well, upward pressure on rates is there partly because we have a high proportion of relatively fixed costs that cannot be changed easily over the short-term. So with lower loads, then there is a greater reduction in revenues than there is a reduction in costs.

When looking at it from another direction, you have to divide the fixed costs over fewer units of sales, and so there is pressure to increase the unit price.

At the same time, lower inflation also has an effect. With lower inflation there is a reduced ability to add the fixed costs of new facilities coming into service and still maintain rate increases at the rate of inflation.

Some of the fixed costs are associated with interest, and while that will eventually change if low inflation is sustained, then there is a long lag before the average interest costs on Ontario Hydro's

debt falls to reflect a lower inflation rate.

So, lower loads and lower inflation tend to cause rate increases at above the rate of inflation, until corrective action can be effective.

Q. I would like to then turn to the other side of the rate issue that you describe, or the financial issue that you have described, and ask you to describe what Hydro has seen by way of customer reaction to the kinds of rate pressures that you have described.

A. As I have said, there is, we believe, a reduced willingness and reduced ability on the part of our customers to accept higher rates. This is partly a response to past increases in electricity rates at above the inflation rate. Over the period about 1991 to '93 there have been accumulated rate increases of about 20 per cent above the inflation rate. In addition, there are forecasts of continuing increases above the inflation rate until about 1995.

This is not a new phenomena. It was discussed by Dr. Long on Panel 10, and he showed a figure illustrating this which was Exhibit 682, that was the overheads for Panel 10, at page 77.

Now, with regard to our industrial customers, then they have to struggle to remain

cost-effective in the recessionary situation with competitive pressures, and one way in which they have brought that quite strongly to our attention and to the attention of others was that in the fall they held a week of protest or a week of public relations activities to highlight their concerns over Ontario Hydro's rates, and we have also had similar indications of opinion through the MEA and their conferences.

In addition of course residential customers have been experiencing the pressures of the recession, some of them have less job security and some would also have experienced unemployment.

The result of all this is that customer priorities have been shifting. That is discussed in the September Board memorandum which is given as attachment B to Exhibit 796, and it is discussed at page 13.

Very briefly, we have indications that rates, reliability, environment, and energy management all remain high priority for our customers, but when asked to place which one is the highest priority, then it is clear that now for our customers, rates is the most critical issue. That's not to say the other issues don't have importance, but rates is the most critical.

Q. All right. How has the kind of financial pressure that you are talking about been reflected in the balance that has to be achieved in planning decisions and how has it been reflected in the decisions that have been taken since Panel 10?

A. It has been reflected in two ways. The first one is that there has been an increased need to manage surplus and to take those decisions now, and there is a reduced ability to afford additional capital expenditures and investments in the 1990s that will add to fixed costs, when these expenditures are forecast to provide potential benefits in the long-term, that those benefits are uncertain. That has been addressed through the 1992 business planning process which, as I have said, has been giving substance to actual surplus management decisions, rather illustrative ones, and that process focuses its analysis on the short to mid-term with the specific analysis extending out over about 10 years. This has had to respond both to the need to manage surplus and to the increased pressures that I discussed.

As part of that process we did develop an economic ranking for managing surplus options and particularly for deferral of options, and that is included as page 1 of our overhead exhibit, which has

just been given the No. 937.

This is based on the March 1992 planning system incremental costs and the derivation of this figure in detail is given in attachment G to our recent exhibit, Exhibit 796. I don't want to discuss the details of this at this point, but just to give some indication of the significance of this figure.

It is significant as an economic ranking for deferral of options, and it also includes some options which would be the mothballing or early retirement of some existing plants.

Those words are important. It doesn't include non-economic factors; they are dealt with separately. It is a ranking and while the absolute values in this figure may change with more recent sets of system incremental costs as the base, we would expect that there would be little change in the ranking of the options, and it is a ranking for deferral of the the new options and it is not an indication of their long-term benefit.

There are several options in that table which have positive long-term benefits even if built on the earliest possible schedule, and still have benefits to deferral. What that means is that in those particular cases, long-term benefit is greater if the

option is deferred until close to the time when the surplus has been eliminated rather than being implemented earlier during the period of surplus.

[9:25 a.m.]

There will be further discussion in later evidence on some of the specifics of this with regard to specific options.

Q. Perhaps you could briefly just outline there, outline where in the material the decisions made as a result of this planning process are recorded?

A. The main business planning decisions were made in September, and they are described in a memorandum to our board of directors, which is given as attachment B to Exhibit 796, and those decisions included such matters as the operations, maintenance and administration decisions, decisions on early retirement programs, and so on.

The capital program decisions were deferred to October and are described in attachment A to Exhibit 796, and that deferral gave time to consider some of the other aspects of those decisions, including environmental leadership aspects, impacts with regards to hearings and with regard to unwillingness to make cuts in the demand management program that would cut

the momentum of that program.

The final set of decisions, most recent set of decisions were made in December, which became necessary because of the revision to the long-term load forecast, which Mr. Burke will discuss, and is described in attachment C to Exhibit 796.

The other factor that triggered decision-making in December was that by that time we had a response from Manitoba Hydro to our request that they consider a five-year deferral of the Manitoba contract.

Now, the overall result of this process as regards this proceeding is that a number of decisions have been made to implement actual surplus management. In many cases the decisions that have been made are similar to the illustrative assumptions that we discussed on Panel 10. To the degree they are different they tend to be decisions made earlier and somewhat more -- stronger decisions, stronger actions which have become necessary to respond to the increased pressures that I have discussed.

Q. Turning then to you, Mr. Shalaby, Mr. Snelson has reviewed, in broad terms, the planning environment that Hydro is facing and has emphasized in part the existence of surplus generation capacity, and

I would ask you to address the question of whether energy management remains or continues as the high priority option that it has been described as previously.

Does it retain that priority in these circumstances?

MR. SHALABY: A. It does. Energy management continues to be a priority for Ontario Hydro, and it could seem a bit -- needing a bit of explanation of why energy management continues to be a priority at a time of surplus that we are looking at, and perhaps to describe some the reasons energy management continues to be a priority I can use this page 2 of Exhibit 937.

That diagram shows the basic load forecast, the requirements for energy or electricity services, and that is a solid line in this graph.

Q. Now, as I understand it, that is the new basic load forecast that Mr. Burke will be addressing shortly?

A. It is.

Q. Thank you.

A. And the dotted line indicates the capability of the Ontario Hydro system to meet those requirements. That capability is the capability of

what is committed, things that are built or under construction, contracts that are signed for example with NUGs, those are the things included in that line.

What the figure shows is that when the dotted line is above the solid line we have a surplus; the capability exceeds the demand. When the situation reverses, which occurs towards the mid- or late '90s, then the demand exceeds the committed capabilities to meet it.

The point I want to make with that diagram is that there is life after the surplus. There is a surplus for a few years, but the situation changes sometime in the '90s, in the late '90s, and resources, demand or supply options would be required in the long term.

Now, there are many options available to Hydro to fill those requirements: non-utility generation contracts, hydraulic developments that we are applying for approval here for, and demand management. So that wedge that starts opening up in the late '90s and continues to grow is an indication that there will be requirements.

And we have said before and we continue to emphasize that demand management is a resource that we give priority to. It is well suited to meeting

requirements that change and have uncertainty to them. We have seen how the gap between these two lines changes. It increases and decreases with many, many factors.

So that is a current snapshot and undoubtedly will change in time.

THE CHAIRMAN: Mr. Shalaby, sorry. I don't mean to interrupt you, but is this No. 2 in 937, does it have its source in 796, this diagram?

MR. SHALABY: Yes.

THE CHAIRMAN: Do you happen to know --

MR. SHALABY: Appendix J, I think provides the numbers for that.

THE CHAIRMAN: Appendix J?

MR. SHALABY: Yes.

THE CHAIRMAN: All right.

MR. SHALABY: It is entitled "Load and Capacity Balance and Production Results". There are computer sheets in there that these numbers are taken out.

So that is the first point in answering the question of why demand management at this time, and the simple answer is in the long term, if we focus long term there will be requirements.

Another reason for continuing with energy

management is the commitment Hydro and the Province of Ontario have made to the vision of an energy efficient Ontario. We have received policy documents here that are filed, and you have received corporate strategies from Ontario Hydro that indicate that an energy efficient Ontario is a vision that is shared amongst government policy priorities and Ontario Hydro corporate strategies as well.

To realize that vision with its associated societal and environmental benefits, a steady and maintained effort in the area of energy management is necessary.

A third reason for continuing with energy management is that many of the options or measures or things that we do with energy management continue to be cost effective even at a time of surplus.

You would recall the total customer cost test that we went through and many other tests that we go through. Many of those measures continue to pass those tests and continue to offer total customer benefits when implemented even at this time of surplus.

A fourth reason for continuing with energy management is the concept of lost opportunities that we talked about. There are things if not done today will cost a lot more to be done later or would

only be possible to do 15, 20 years from now.

Examples would be insulating houses well at the time of construction. If it is not done at that time then it is very expensive to do it at a later time. And there are many other examples of renovations and changing production processes and things of that nature. If not captured at the moment it is done it becomes very difficult to do later on.

Finally, and it is a concept that we introduced both in Panel 4 and Panel 10, is the notion of energy management is more than just reduction of megawatts on the system. It is the customer energy service aspect of our business, it is adding value to the products that we sell to customers. Customers indicate that they want Hydro's help in reducing bills and managing their electricity bills, and that is what energy management does for them.

So for all those reasons we continue to put energy management as a high priority and consider it a core business for the company.

MR. B. CAMPBELL: Q. Now, recognizing that it is still a priority and still makes good sense, nevertheless I take it that energy management activities are impacted somewhat by the changes in the planning environment that Mr. Snelson has addressed?

MR. SHALABY: A. They certainly have. One of the profound things that have changed is the state our customers are in. Energy management is working with customers and serving customers and our customers today are certainly hurting with the economic conditions. Their priorities are different, their activities are different, so we have to respond to those changes and serve them in this current set of needs.

What they are looking for is to become more competitive and to reduce their costs, and that is the focus for energy management at this time.

The economic situation when it changes as well results in a change in the attainable potential for energy management. If we are not building as many office towers or if the steel company is not expanding or -- there are many opportunities for energy management. If they are disappearing or if they are appearing elsewhere then the potential continues to change.

A third area for change in the environment in which energy management operates is the extent of participation of various players in the energy management field.

We indicated that energy management is a

partnership between governments, customers, manufacturers and Hydro and many others. An example of a place where Hydro has found its participation less required now than we thought a few months ago is the area of converting from natural gas to electricity -- or from electricity to natural gas, I'm sorry. [Laughter.] This is not a Freudian slip.

So what we have is the price of natural gas continuing to go lower and the price of electricity continuing to go higher, and we see now that the price differential is sufficient for most people to do the conversions without incentives from Hydro, financial incentives. So the role of Hydro in this business is seen to be changing from possibly providing or planning to provide incentives into providing information to customers to base their choices on the best information available.

Finally, one of the other changes that continue to take place, and it is not necessarily because of the economic conditions, it is just because of our experience in the business and the years that we have had in dealing with customers, is that we continue to pick the winning ways of implementing programs, ways that work better than others and discard ways that do not work. And we said that in Panel 4 and we said in

Panel 10 that we will continue to modify our design and our delivery mechanisms to meet customer requirements, and that is an ongoing activity and continues to happen in energy management.

Q. Could you give us some examples as to how that is reflected now in energy management programs and strategies?

A. One of the examples in that is the increased emphasis on taking the customer perspective in energy management, and in Panel 4 we explain programs that, for example savings by design, where we sit with a designer of a new building and explore opportunities for energy efficiency and work with the designers and architects to achieve those opportunities.

It is going along those lines in most other programs. We want to understand customer requirements and work with the customer to see what is it that they need as opposed to developing a product, an efficient product and then go look for a buyer for the product. So instead of being product- or technology-driven and then finding a market for it, we will start with the market, see what the market needs, and then develop products and services to meet that market requirement. So we are shifting more and more

towards that. That has worked well and we want to generalize it as much as possible in our services.

So you will find us going into partnerships, and we explored that in Panels 4 and 10 as well, but we will go into formal agreements, partnership agreements with our large customers to work with them, to see what their schedules are for overhauls and changes and to understand the requirements and work with them.

One other area of change, again ongoing, happened before, will happen again, is that some programs will get accelerated, some will get cancelled, some will get phased out earlier than anticipated.

[9:40 a.m.]

At this time, for example, we are phasing out earlier than anticipated a program to do with streetlighting. We feel the job has done very well. The infrastructure in the province is in place. There have been many demonstrations of how well efficient streetlighting works, and we think we can now withdraw from that market and many municipalities, the remaining ones, will in fact move to streetlighting that is efficient on their own.

Programs that we thought we would launch from a demonstration or pilot into full scale program

that we decided to cancel would be the fridge buy-back program. We started some private work on picking old fridges and paying people for giving us their old fridges, we decided not to make that a general program in Ontario, again because we think this will happen on its own. The acceleration of that is not necessary at this time.

So on going modifications to programs is something that we continue to do.

Again, the area of fuel switching is worth mentioning. We recognize that the market forces will take care of much of the fuel conversion without financial incentives from Hydro.

So all of these efforts continue to focus our business on being more effective and efficient and meeting the customer requirements.

Q. And what are your expectations for the long-term contribution of energy management given its priority?

A. Well, our expectations continue to be that we would like to get all the economic demand management opportunities that are available out there. That has been our position in the early demand/supply strategy and all the evidence that we have given so far is that all the economic opportunities are going to be

targeted and we would like to harvest all of that.

Those opportunities and estimates of those opportunities have changed in the past and continue to change. They are a function of what we think is going to be out there, how the economy is going to develop, how customers are going to make choices about efficient equipment, relative energy prices, and the many, many other factors that come into determining the potential for energy savings. So that potential has changed and will continue to change.

The number of players in the business continue to change and the role of different companies continues to change, and that is also something that we expect and is ongoing.

The most recent outlook for the attainable energy management potential is customarily contained in the load forecasting document. That has been the case over the several years that the load forecast document contains a chapter on the attainable energy management and that continues to be the case.

So Mr. Burke's load forcast has, in chapter 5, the attainable load reduction possibilities. So that is where our most recent outlook resides.

Q. I would like to turn to that, Mr. Burke, but just by way of introduction, can you remind

the Board, please, of which load forecast it was that you spoke to on Panel 1, and give us sort of a chronology of load forecast production since that time which seems an amazingly long time ago, but I suppose really isn't.

MR. BURKE: A. Evidence on Panel 1 which was in May 1991 was based on the 1990 load forecast which had been approved the previous December, December of 1990.

Panel 10 evidence was based on DSP Update load forecast, and that was finalized in October of 1991. It incorporated the new scenario for demand management that was introduced in Panel 4 and also made adjustments for lower Ontario GDP and higher electricity prices.

The 1992 long-term load forecast, which is attachment C of Exhibit 796, was produced on its normal schedule, the first in a while, and was approved at the December 1992 Board meeting, just last month.

Q. Okay. Now, one of the terms of art that have been spoken of throughout, and Mr. Shalaby has referred to, is the basic load. I would like you just briefly, please, to remind the Panel of the distinction that is made in your forecasts between basic load and the primary load.

A. Page 3 of Exhibit 937 contains simplified definitions.

Basic load should be familiar to you. It is the load on Ontario Hydro that - I should emphasize on Ontario Hydro, not the province as a whole - that would result from the operation of market forces.

Since the concept of basic load was introduced, efficiency standards have been treated as if there were a market force.

Primary load is then derived by subtracting the net impact of demand management from basic load.

Q. I would like to turn to the matter of standards for a moment. The definition of basic load, and in Panel 1, you said that well-defined standards are built into the basic load forecast, and has that concept changed in any way?

A. No, essentially it's the same. But over time a great deal of work has been done concerning standard setting in Ontario, so we have greater confidence now in the direction and content of future standards, efficiency standards for Ontario.

Hydro has been working closely with the Ministry of Energy and has adopted a list of standards for the 1992 basic load forecast that corresponds to

ones which the Ministry considers either already implemented or ready to be implemented or which are highly likely to be implemented.

Now, as you may recall, in the update that was made to DSP, there was a set of generic standards on top of the well-defined ones that were included in the basic load forecast. There was a set of generic standards that contributed to the achievement of provincial electrical efficiency improvement goals.

In the 1992 load forecast, however, all of the impact of standards is now captured in the basic load. That means that for the purpose of a comparison to the DSP Update load forecast, it is appropriate to include the impact of these extra standards, the ones above and beyond the well-defined ones previously included in the DSP Update load forecast, these extra standards, along with the EEI forecast, to make a valid comparison, between the EEI estimate we made at of the time of the DSP Update, and the total electrical efficiency improvement impact we are now making.

Q. And with the revision to the basic load forecast, I take it you would have revisited the estimates of the potential that exists for demand management?

A. Yes. I referred to the appropriateness of reconsidering the opportunities for efficiency improvement in fuel switching as the basic load forecast itself changes.

I might mention that in doing so, the 1992 primary load forecast used the 1992 basic load forecast throughout to re-estimate demand management potential.

I just mention this because it wasn't quite as clean in the 1990 case.

As Amir did indicate, hydro bases its estimate of economic induced potential for demand management on the maximum economic demand management that is not captured by the basic load forecast.

The total economic potential for induced electrical efficiency improvement and fuel switching was re-estimated in September with an enhanced set of technologies, and these were screened against the latest available system incremental costs.

On the other hand, in the same process, there were changes in cost estimates that eliminated some options and reduced others. Also the eligibility of some measures was reconsidered.

In moving from the total potential to the attainable amounts, the amounts that we can actually

achieve in the marketplace, we apply penetration rates to the program driven potentials that we identify. Now there has been no change made to the estimates of penetration rates used in this load forecast.

Q. Briefly then, can you outline the major changes in the 1992 load forecast compared to the forecast used in the Update and for Panel 10?

A. The major change in the short-term is that 1994 load is down about 7 per cent from the October 1991 forecast.

In the long term, the basic load continues down about 7 per cent right through to 2015. Nonetheless, primary load beyond 2000 is very similar to the DSP Update, and that's because the impact of program-driven demand management as re-estimated is much reduced.

Much of the effect of efficiency improvement and fuel switching now occurs through standards or as a market response to relative fuel prices and is captured by the basic load forecast.

Q. Now, I want to take a look at that proposition in a moment, but I would ask you first to summarize the changes to the outlook for some of the major macro economic drivers that you have spoken of or that have been spoken of earlier in these proceedings;

that is Ontario gross domestic product and energy prices. If you would address those two, and then I want to come back to this business of the particular changes in the load forecast.

THE CHAIRMAN: Mr. Burke, could you just go a little bit slower. This is fairly meaty stuff for me at least and it is hard to follow it. You are going a little too fast for me.

MR. BURKE: Sorry.

Ontario GDP for 1992 is 6 per cent below the level forecast for 1992 in the DSP Update. Now this is due to revisions to historical data.

MR. B. CAMPBELL: Q. Stopping there. When you say revisions to historical data, this is things like StatsCan has gone back and adjusted its numbers?

MR. BURKE: A. That's correct. In the the case of 1990, for instance, it was originally estimated that GDP grew about -- well, contracted about 1.9 per cent, the current estimate as of September is that it actually contracted 3 per cent.

The forecast, the actual value for 1991 is also running at around minus 3 per cent. So that over the two years, '90 and '91, the economy in fact grew about 6 per cent smaller in Ontario and made this

recession the worst since the Great Depression.

Also, forecast growth rates are lower; that is, for the years '91 and '92 we have revised our projection of what the path of the recovery would be. In last year's forecast, 1992, was to have been the first year of a strong recovery, 4 per cent growth had been forecast for 1992 in 1991. Now it is forecast - and I say forecast because we haven't seen the actual yet - to have grown at 1.8 per cent, and the recovery path has been delayed one year in the current forecast.

Beyond 1994 GDP growth is actually faster than the forecast made last year, and this is because the population projection that underlies the GDP forecast has an additional half million people by the year 2015 living in Ontario than we previously projected.

With the additional population GDP, per capita is roughly the same so that GDP grows more rapidly, and as a result we forecast that we will recover about 4 percentage points of the output that we have lost in the last few years by 2015. So the 1992 economic outlook comes to within 2 per cent of the economic outlook made last year by the year 2015.

Turning to energy prices and starting with electricity, while there are electricity price

increases in the near term in this year's forecast, the price projection for electricity is actually very similar to the one that was used last year, at least until 2005, and any changes, any increases which there are increases beyond 2005, do not have much impact on the current load forecast.

Electricity prices were flat during 1980s. They have risen 22 per cent between 1989 and 1993, and they are expected to rise another 5 per cent by 1996 in real terms.

On the other hand, natural gas prices fell 60 per cent from 1983 to 1991 and are now forecast to continue to fall for another year or two. When they do rebound, they are expected to recover to levels over 20 per cent less than those anticipated last year.

This forecast change solidifies into the long term the current relative prices between electricity and gas. These are depicted in overhead No. 4 for the residential sector. The retail prices are indexed relative to 100 per cent for electricity, so that you can read off the relative price of natural gas to electricity from the vertical axis.

As is apparent, the price differential has been in gas' favour for some time. But I think the important point is that consumers may not been

confident that it would persist that way until more recently. It's only since 1989 that there is evidence that electricity space and water heating customers were starting to shift away from electricity to gas and, to a lesser extent, to oil.

In fact, the data on this trend were not yet available when we were preparing 1990 end-use load forecast. So that this forecast, the 1992 load forecast is the first time an end-use projection has reflected the significant customer response that we are now experiencing to the relative price differential in these end-uses.

[9:55 a.m.]

Another area where this price differential is evident is in the intensified interest in load displacement non-utility generation where I think it is fair to say that increased confidence of our larger customers that this price differential that we see now will be maintained or increased in future has led to them pursuing more actively load displacement non-utility generation possibilities.

DR. CONNELL: Mr. Burke, could you just explain the meaning of 'per cent of electricity adjusted'? Is there some historical reference for it?

MR. BURKE: 'Adjusted' refers to

efficiency adjusted. Sorry, I didn't make that clear.

The price of natural gas is adjusted for the fact that it is 65 per cent -- well, the adjustment that is being made here is that it is against a 65 per cent efficient heating system versus electricity at 100 per cent. So if I was to plot the raw values per Btu it actually would be more extreme than what you see here; that is, the fact that there is a difference in the utilization efficiency of natural gas and electricity has been partially adjusted for here in the way the numbers are plotted.

DR. CONNELL: I can think of this as being in the residential context?

MR. BURKE: That's right. This is the residential, sort heating costs you might think of.

The fact that a Btu input of heat to a furnace, only 65 per cent of it necessarily -- sorry, Btu of gas input to the furnace, only 65 per cent of it may emerge as heat in your house.

Now, there are different efficiencies of gas furnaces and there are different efficiencies with which electricity can be utilized as well, but we have made a standardized adjustment for, you might say, the heating costs of electricity and gas in making this plot.

THE CHAIRMAN: Is this diagram in attachment C?

MR. BURKE: It is not exactly in Exhibit C. I think all the data for it is contained in Exhibit E, the Energy Price Trends report. A very similar version is contained in Exhibit E. It may not be scaled to the 100, but it is -- I could get the page for you at the break.

MR. B. CAMPBELL: I noticed as we started this morning, Mr. Chairman, that we have neglected to put the sources on the charts as we usually do, and we will supply a list of sources tied with a cross-reference to the pages here.

That should have been done over the course of many other activities over the holiday season. It did not get done, for which I apologize. But we will supply the sources.

MR. BURKE: It is a version, essentially the same data as in figure 29 on page 39 of attachment E of Exhibit 796.

THE CHAIRMAN: Give me that again?

MR. BURKE: It is the same data as in figure 29, which is on page 39 of attachment E of Exhibit 796.

THE CHAIRMAN: Thank you.

MR. B. CAMPBELL: Q. Now I would like to pick a particular point of 1994 as a starting point in looking out over the load forecast and indicate that the load forecast for 1994 has been reduced 7 per cent since the Update was prepared and the Panel 10 evidence was given.

What are the major reasons for this?

MR. BURKE: A. Well, actually by the end of 1992 load already was down 5 per cent from the forecast we made in October of 1991.

This change may be attributed basically to the very weak economy in Ontario and especially to the weakness in key energy-intensive industries, such mining, pulp and paper, chemicals and steel.

The fuel switching and the load displacement non-utility generation effects I was talking about a minute ago, while these are gaining momentum they are not yet a significant part of the reduction in load that we have seen to date.

There is an additional 2 per cent decrease in forecast from 1992 to 1994, and I would attribute this 2 per cent to weaker prospects for the industrial customers than we had previously anticipated and accumulating natural fuel switching effects, which are the customer response to the relative price

difference between electricity and gas.

Q. Now, can you again just briefly summarize the major reasons that you see for the new basic load forecast staying about 7 per cent below last year's forecast right through the period '94 through to 2015?

A. Well, there are a number of factors which are offsetting that combine to keep the forecast down about 7 per cent.

On the negative side the impact of additional efficiency standards above those already in the DSP Update builds to about 800 megawatts by the year 2015, and that is equivalent to about a 2 per cent reduction in the 2015 basic load.

Also space and water heating loads are 20 per cent lower than they were in the DSP Update basic load, contributing another 2-1/2 per cent cut in the year 2015.

All this time Ontario GDP is actually growing faster, as I said, making up some of the lost ground of the past recession, but it does still end the period 2 per cent lower in 2015 than we had previously forecast, and this translates fairly directly into a reduction in basic load of about 2 per cent.

The growth is uneven. The number of

households in this forecast is up from before, but the growth in electric-intensive industries and commercial floor space is, relatively speaking, slower than before.

Q. Now, Mr. Shalaby in his evidence talked about delaying some programs, some reduced opportunities for demand management as a result of lower economic growth.

How does the demand management impact contained in the 1992 load forecast compare to the demand management scenario described to the Board in the Panel 4 evidence?

A. Page 5 of Exhibit 937 is an overhead that draws on data from attachment C. There are one or two items here under Fuel Switching Market-Driven, which I will explain in just a minute, which are slightly different from the information presented in attachment C. But otherwise, the remainder of the information is contained largely in chapter 5 of both -- of attachment C.

Now, this overhead compares the components of the Panel 4 demand management case for the year 2000 with the corresponding elements of the 1992 load forecast for the years 2000 and 2005, which, as we said earlier, constitutes the evidence for Panel

11 concerning demand management.

Now, I am going to discuss the components item by item in a minute, but I want to look now at the totals and also this distinguishing feature between the Panel 4 and Panel 11 columns, which is that we have included --

THE CHAIRMAN: I take it you are calling this, what we are doing now, as Panel 11; is that right?

MR. BURKE: I guess so. Is that not --

MR. B. CAMPBELL: We have adopted that vernacular.

THE CHAIRMAN: All right.

MR. BURKE: I hope it is a short panel.

Nonetheless, at the top of the Panel 11 columns you will note that there is a box labeled "FS Market-Driven", which is fuel switching market-driven, but there is no such box at the top of the Panel 4 column.

It is important to note that when we were preparing the estimates for fuel switching potential for Panel 4 that the basic load forecasts that we were using at the time did not contain any market-driven fuel conversion in the space and water heating markets. This is for the reason I gave earlier, and that is that

basic end use forecasts that were used at that time were made prior to the data emerging that customers were actually responding to the relative price differential that had existed for many years between gas and electricity in these switchable market segments.

On the other hand, the 1992 load forecast does include market-driven fuel switching in the basic, both in the form of conversions of existing stock and due to reduced market shares for electricity in new buildings for space and water heating loads.

You can see that the total for the years 2000 and 2005 in the new load forecast bracket the results that we got for Panel 4 when the market-driven fuel switching is included.

MR. B. CAMPBELL: Q. All right. I want you to go through this comparison, then, starting with the EEI boxes and take us through the major factors which have altered the attainable potential for demand management as estimated last year for the Update. Again, if you would start with the energy efficiency improvement area.

MR. BURKE: A. Well, on Panel 4 for the year 2000 EEI, electrical efficiency improvement, was estimated to reduce demand 2,225 megawatts. Of that,

1,535 megawatts, the bottom box on that column, was to be achieved through programs and 690 megawatts through the generic standards I referred to earlier in the presentation.

These standards were described in Exhibit 258 and entailed achieving half of the remaining economic EEI in eligible end uses, which were identified there.

Now, over the past year both the Ministry of Energy and Hydro have worked to define standards and assess in which areas they may likely be implemented.

The set of standards which Hydro has included in this year's basic load forecast has impacts that exceed the generic standards proposed for the residential sector but falls short in the commercial sector.

The total impact of new standards in the year 2000 in the basic is now 350 megawatts, about half the number, 690 megawatts, that was previously identified and included in the EEI scenario in Panel 4. So this 350 megawatt change, roughly, reduction between the standards in this year's forecast and last time is one of the elements of reduced EEI by the year 2000 in this load forecast.

Now, as far as programs are concerned, in

the 1992 load forecast program-driven EEI is down about 10 per cent. From the 1,535 megawatts it drops about 150 megawatts to 1,390 megawatts in the year 2000. This change reflects lower avoided costs, lower eligibility for measures, and slower growth in key market segments as has been mentioned before.

But positive factors also apply. There were additional technologies, and there are additional programs where standards were not put in place that we had anticipated in the previous forecast.

Now, in total, including the incremental standards, and so putting it on an equivalent basis to last year the EEI component reduces primary demand 1,740 megawatts in the year 2000 in the current load forecast, which is about 500 megawatts less than on Panel 4, and the two components again are the 350 megawatts of reduced standard impact and the 150 megawatt reduction in programs on net.

By 2005 the total impact is 2,550 megawatts for EEI. That is the sum of standards plus programs, and that does exceed our scenario for the year 2000 that we had on Panel 4.

Q. All right. And can you take us through an --

THE CHAIRMAN: Just one moment. There is

quite a dramatic increase from 2000 to 2005 in those two elements. Is there any particular reason for that?

MR. BURKE: Well, there are five more years of stock replacements and new stock to work with.

The numbers you are looking at for the year 2000 reflect eight years of programs and standards -- well, even only about five years of standards for the most part, whereas we have nearly doubled the time for standards to work by 2005 and the programs are ramping up so that it gives considerably more time for program impacts to occur in those five years.

MR. B. CAMPBELL: Q. And can you take us through a similar comparison then with respect to the fuel switching, again looking at the 1992 load forecast as compared to the situation when we left off with your evidence in panel 10?

MR. BURKE: A. The scenario for fuel switching in Panel 4 was to achieve 1,275 megawatts by the year 2000. Of these, 575 megawatts were to come about through programs and 700 megawatts was to come about as a result of government regulations which would mandate the use of a fuel other than electricity for space and water heating in new buildings. This was the assumption made in the scenario at the time.

In the 1992 load forecast by the year 2000 the combination of market-driven changes in existing and new markets and program potential is estimated at over 1,100 megawatts; that is, looking at the fuel switching programs box of 240 megawatts and the market-driven fuel switching at the very top of the column of 880 megawatts. The sum would be more precisely 1,120 megawatts.

This means that total fuel switching impacts between this forecast and the last one for the year 2000 are down less than 200 megawatts from the DSP Update scenario. However, programs are only 240 megawatts of that. The remaining 880 megawatts is market driven, and there is no mandation in the new market.

Market forces are encouraging customers to convert some types of existing space and water heating systems, not all. The relative price advantage of natural gas also has a major role to play in the new market shares forecast for electricity in those segments.

By the year 2005 the total fuel switching effect is estimated to be 1,800 megawatts. That is the sum of about 400 megawatts of fuel switching programs and about 1,400 megawatts of market-driven fuel

switching.

Now, that sum in the year 2005 is more than the year 2000 projection, but it is actually less than we had projected for 2005. So it is not out of line with last year's projection in total.

Now, for those of you with a particular interest in the health of the space heating market in Ontario I think it is worth observing that the 1992 primary load has about the same electric heating in it even though program contributions are much lower than before, as the DSP Update primary load forecast had. It is just distributed differently between the basic and the primary, between the basic load and induced programs.

In both forecasts space heating load in total does not contribute to growth in primary load.

Q. Now, the other components of this chart are demand management and load shifting and discount demand service, the other components of demand management, that is.

I understand that these two items, discount demand service and load shifting, affect peak not energy, and perhaps you could just indicate whether they have changed since the load forecast use for the Demand/Supply Plan Update.

[10:15 a.m.]

A. The forecast for discount demand service which was previously called capacity interruptible loads is the same, 700 megawatts, as made on Panel 4, although I would acknowledge that in the intervening time there have been various different projections with different numbers, but we end up in Panel 11 with roughly the same number as in Panel 4.

Having said all that, I think it is still fair to describe the discount demand service forecasts presented here as preliminary and approximate, though it isn't going to vary very much from the 700 megawatts that I have shown on this overhead.

Load shifting was projected to contribute about 1,000 megawatts of peak production on Panel 4. As described in Panel 10, the load shifting forecast was reduced 750 megawatts in 2000 in the Update load forecast, and it is now projected down to 600 megawatts in the year 2000. This is partly because the response to time-of-use rates to date has been less than anticipated, and partly because it is now recognized that the discount demand service itself reduces the attractiveness of load shifting in response to time-of-use rates.

Q. Now, you have shown how the overall

demand management effort described in Panel 4 has evolved in the 1992 load forecast, I guess the question that occurred was, what does the new primary forecast tell us about whether we are achieving the larger goal of energy efficiency in Ontario?

A. Yes, an interesting question. Unfortunately, there is no simple way to measure electrical efficiency for a province and how it changes. But what I can show you and what is plotted in page 6 of Exhibit 937 is electrical intensity in Ontario and how it compares between this forecast and the last two that we made.

By electrical energy intensity I mean the ratio of primary electricity demand to Ontario GDP. Now, the primary electricity demand numbers that lie behind this plot are contained in Chapter 1 of exhibit -- attachment C of Exhibit 796, and the Ontario GDP numbers I think most of them also, but perhaps for the 1990 estimates one will have to go to the 1990 load forecast document.

Amazingly enough, the exhibit number for that escapes me.

Q. I am sure there is, but I don't have it to hand. We will again include it on the list of sources.

A. Okay.

Now, the ratio that electricity intensity represents; that is, the ratio of primary load to Ontario GDP, may change for a variety of reasons that have little to do with efficiency improvement per se. But I do take some comfort from the fact that as this overhead shows, electrical intensity is falling faster in this forecast than it did in the previous one and converges to a level as low as the previous one did last year, beyond the year 2000. This occurs despite the fact that demand management programs that are included in the 1992 primary load forecast are of smaller scale than in the DSP Update.

Q. Now, the primary load forecast is, as you pointed out, at the beginning of your evidence, the load that occurs on Ontario Hydro, not the load in the province as a whole, and perphaps you could remind us of the distinction, that distinction again.

A. Okay. Apart from transmission and distribution losses, the major difference between total Ontario electricity consumption and the demand on Ontario Hydro is the electricity produced by load displacement non-utility generators.

In all the forecasts submitted to this Board, load displacement NUGs have come up in two

places: Natural load displacement NUGs are subtracted from provincial demand as part of the process of deriving the basic load forecast, and program-driven load displacement NUGs are subtracted from the basic load on the way to calculating the primary load.

Q. Now what changes have you made with respect to the amounts of load displacement NUGs included in the 1992 forecast, again as compared to the DSP Update forecast?

A. With the change in the natural gas price forcast, combined with the change in expectations concerning the relative price of electricity and gas, the adoption of load displacement NUGs in response to market forces have been accelerated in this forecast. By the year 2000 natural load displacement NUGs are about 200 megawatts higher than we said they would be last year.

On the other hand, program-driven load displacement NUGs do not increase beyond 1994. This is a result of the cap on NUGs that was introduced in the DSP Update. So they in fact are down about 17 megawatts in the year 2000 from what we said last year.

On net, the total load displacement NUG effect is up about 150 megawatts by the year 2000.

Q. Again, the original, if I go right

back to the original Demand/Supply Plan submission and the subsequent load forecasts, these have included as well a probability distribution around the median load forecast. You have been showing the median line so far in your presentation this morning. The measure of uncertainty that you have most commonly depicted has been an 80 per cent bandwidth. It has a confidence band around the primary load forecast, have you made any changes to the methodology used to derive those bandwidths since your last appearance here?

A. No, the methodology is the same. The bandwidths have slightly different properties as described in chapter 6 of attachment C of Exhibit 796.

The plot you see is from page 140 of attachment C of Exhibit 796, and as you can see, while they are not exactly the same, they are very similar bands compared to those used last year, and you see the median forecast tracking very closely beyond the year 2000 as I described earlier.

Q. All right. And relative to the original 80 per cent band in the original filing, where does the current forecast lie? I guess the next chart shows us that, does it?

A. Yes. This chart, page 8 of Exhibit 937, draws on the confidence band in the original DSP

submission, Exhibit 3, and the numbers from Chapter 6 of attachment C of Exhibit 796.

What this shows is that the median 1992 load forecast is running between the low and the median of the previous -- sorry, of the DSP, original DSP load forecast for primary load submitted to this Board.

I think it is also interesting to note that despite fairly dramatic circumstances in the last few years, the current loads fall within the original 80 per cent bands submitted to the Board in the original 1989 submission.

What I would conclude from looking at these two overheads is that most of the change in the primary load forecast, and it's associated uncertainty band occurred between the DSP the DSP Update and not since then.

MR. B. CAMPBELL: Mr. Chairman, I have forgotten when on this new schedule you take morning breaks. If it's now, this is a convenient time.

THE CHAIRMAN: Well, no tradition has been established. I was going to go to a quarter to eleven in order to make the second segment of the morning less than the first.

MR. B. CAMPBELL: I am quite satisfied to do that. I will watch for the right place. There are

a few convenient places coming along.

Q. So that then brings me back to you, Mr. Snelson. I want to ask you to briefly outline changes that have taken place with respect to Hydro's non-utility generation programs again since Panel 10 gave its evidence.

MR. SNELSON: A. Well, the adjustments that have been taking place in the non-utility generation program are in the direction of tending to reduce the amount of purchases in the 1990s. We don't want to buy any more generation in 1990s if it's not needed, and we don't want to buy it if it's going to add to the rate pressures. And this is a response to the rate pressures and to the surplus issues that I discussed in the earlier evidence.

This process started before Panel 10. At that time we indicated that we were not accepting proposals for non-utility generation over 5 megawatts, although we were continuing with negotiations of all projects that had status to negotiate, and we would accept new proposals for renewable projects above 5 megawatts.

In addition, one of our illustrative surplus management assumptions was some reduction in the amount of non-utility generation that we would buy.

The October decisions were in the direction of further reducing and tightening the requirements for non-utility generation, and at that time the process was changed and we said that we would not accept any non-utility generation over 5 megawatts of any kind. And it's the situation following the October decision-making that is the projection of non-utility generation which is used later Mr. Dalziel's evidence on the current load and capacity balance.

There was, however, another more recent set of decisions which were taken at the December board meeting and are not reflected in the projection which Mr. Dalziel will show you, and that decision was a decision to put on hold all non-utility generation projects for some period of time. Now this hold --

THE CHAIRMAN: That includes under 5 megawatts, everything?

MR. SNELSON: Yes. I will come to perhaps a more precise definition.

The intention was to put on hold projects so that each one can be examined as to the options available for that particular non-utility generation that would contribute to easing the surplus and the rate pressures that we have discussed.

There isn't a precise time frame associated with the hold, but it is expected to be of the order of two months.

The projects that are on hold are all those, both above 5 megawatts and less than 5 megawatts that do not have full approval, and full approval would constitute going right through to having an Order in Council. So all projects that do not have Order in Council approval are on hold and that affects about 1,300 megawatts of projects. At this time I can't speculate as to what will be the result of that process, but that is the intent of the process, to see what can be done to further act in the direction of reducing surplus and easing the rate pressures.

MR. B.CAMPBELL: Q. In that regard what is Hydro's current policy with respect to load displacement generation, and I guess I would ask you to -- that relates particularly to industrial projects and municipal utilities, and again can you outline whether that policy is any different from the approach that was in place at the of the conclusion of Panel 10 evidence?

MR. SNELSON: A. The situation today with respect to industrial load displacement non-utility generation is that we are no longer

providing financial assistance for load displacement non-utility generation. We have discontinued our financial assistance plan. That is also responding to an OEB recommendation that we do that.

But of course industrial customers can still choose to self-generate if they wish to do so without financial assistance from us.

As Mr. Burke has explained, he does have in his December 1992 load forecast increased demands of load displacement non-utility generation in the industrial sector.

With regard to the municipal utilities and municipal customers, then this is quite a complicated issue. There are a number of practical and policy issues surrounding the concept of the public power pool, the partnership between Ontario Hydro and the municipal utilities, and this issue is currently being reviewed by a task group with membership from the Municipal Electric Association, membership from Ministry of Energy, of the provincial government, and members from Ontario Hydro.

I think it is well-known, it's been reported in the press, that Ontario Hydro is discouraging municipal utilities to self generate in the current circumstances. We believe that it weakens

the power pool and that it increases costs in total.

We recognize that it may lower costs to the particular utility that chooses to self generate, but that the increase in costs to all other utilities is higher than the saving to the utility that decides to self generate. As I say, these are complicated and difficult issues and it is these issues that are being addressed through this particular task group and they have not yet reported.

Q. Now despite these changes affecting non-utility generation in this period over the 90s, have there been any changes regarding Hydro's views of the long-term availability of non-utility generation as a supply option?

A. No, there has been little change in our long-term expectations with regard to the availability of non-utility generation.

We still expect over the long term that NUGs will be available at least to the extent that was discussed by Mr. Vyrostko, Mr. Brown and myself on Panel 5.

We still expect in a non-utility generation will be an important contributor to the flexibility that we need and that was described in the response portfolio which was put forward in the DSP

Update which was Exhibit 452.

The most significant factor affecting the long-term availability of non-utility generation is with respect to the forecast price of natural gas. I believe that Mr. Burke has referred to this in a slightly different context but it was the same forecast of natural gas prices that I am discussing here.

This figure, which is figure 9, page 9, of Exhibit 937, is reproduced from the November 1982 energy price trends report which is attachment E to Exhibit 796. This is taken exactly from that report. This shows that in the last year since the fall of 1991 through to the fall of 1992 we have made a significant lowering of the forecast price of natural gas in the future. I believe this is consistent with Mr. Smith's evidence on Panel 8 where he indicated that, if anything, we were more likely to lower our gas price forecast than to raise it. This shows a reduction in the future price of natural gas of the order of 20 to 25 per cent.

I would caution you in looking at this figure to recognize that it is not quite on a true zero, in that the zero is somewhat below the lower axis.

The effect of this reduction is to

increase our confidence that non-utility generation will be available over the long run at reasonable prices.

Q. Against that background, what level of non-utility generation has been assumed in the most recent load and capacity energy production analysis that Mr. Dalziel will be speaking to?

A. With respect to the load displacement non-utility generation, then that is accounted for in the primary load and has been covered by Mr. Dalziel.

With respect to the purchase non-utility generation, then that is accounted for in the primary load and has been covered by Mr. Burke.

With respect to the purchase non-utility generation, then that is shown in attachment F to Exhibit 796, that is reproduced here as page 10 of Exhibit 937.

This shows the projection to the year 2000, and by the year 2000, because of the way in which our contract discussions have developed, the level that is shown is somewhat higher than was shown in the illustrative surplus management that we discussed on Panel 10. And this level is based on the status of the existing negotiations and contracts prior to the hold that was put on in December. This schedule is not

based upon when we need the non-utility generation; this is based upon what would result from the development of the contracts that were under negotiation and had status to negotiate.

[10:35 a.m.]

Beyond the year 2000 the situation is somewhat different.

Our assumption is that generally speaking additional non-utility generation will be available when needed, and we have assumed for the purposes of projection that it will be available up to the level that was indicated in the Update and discussed in Panel 10, and that will be shown in the analysis discussed by Mr. Dalziel.

It is quite possible, in fact it is likely, that more non-utility generation will be available than is shown in that prediction.

You will recall that in Panel 5 the long-term projection of non-utility generation was based upon the potential for cogeneration and that in addition to that there is a potential for major supply non-utility generation, which would not be associated with cogeneration. And that is still the case, and we continue to rely on NUGs for a considerable degree of our upward flexibility.

Q. If I can ask you then to turn to the situation with respect to the hydraulic option, again can you advise what changes have taken place in Ontario Hydro's activities in the hydraulic project areas since Panel 10 gave its evidence?

A. Panel 10 evidence was based on a case which, as we have said several times, had illustrated management of the surplus, and the process in 1992 was to try and come to actual decisions on how to manage the surplus and those decisions or the discussions of them are in the September and October board memos.

Now, the results of that process are shown on the next figure and compared to the managed surplus assumptions that we had in Panel 10. This is page 11 of Exhibit 937, and I believe it is an exact reproduction of table 5-1 of Exhibit 796.

The actual results that we have come to have been quite similar to the illustrative surplus management. In both cases the Niagara and Mattagami projects are maintained around the year 2000.

Now, you will notice from this table that the Niagara power house in the illustrative surplus management was assumed to be deferred to the year 2009. You will recall perhaps from that evidence that only the power house was deferred to 2009 but the intention

was to build the tunnels which would provide the major energy benefit for around the year 2000. The current assumption is that both the tunnels and the power house would go ahead around the year 2000 for completion by 2002.

With respect to the Little Jackfish and Patten Post projects then, both the DSP Update illustrative surplus management and the current set of assumptions has those projects deferred out of the 1990s, that they would not be built during the period of surplus.

There is some difference in the dates. In fact, Little Jackfish we saw as an illustrative assumption is being cancelled, but I think the important factor here is that both are seen as being -- that they should be deferred out of the period of surplus to a later period in the plan, and that is still to some degree open as to exactly when that should be.

Now, the deferral of Niagara and Mattagami projects was considered in the business planning process in 1992, and it was rejected because the savings of deferral were quite small and the benefits that we discussed with these projects on both Panels 6 and 10 we believe still apply, and

consequently the decision was taken to continue with the projects for around the same in-service dates as before.

Q. And has evaluation of the cost/benefit ratios changed since Panel 10 with respect to these items?

A. No, we have not done a new set of cost/benefit ratio evaluations.

The last set that was done was based on the March, 1992 system incremental costs and was discussed on Panel 10, and as a reference it was actually shown on page 76 of Exhibit 62, which was the overheads of Panel 10.

Now, you will be aware that in the Exhibit 796 package is a revised set of system incremental costs that were issued and given the general name "November, 1992 Values", and that is attachment D to Exhibit 796. In those values the long-term benefits are a little lower, by about 10 per cent, and so cost/benefit ratios if re-evaluated with those values would deteriorate by about 10 per cent.

In point of fact, that would return them to quite close to the values that were current at the time of Panel 6, which were shown in Exhibit 359 on figure 3, which -- so we have gone from Panel 6 which

had one set of values to Panel 10, they are about 10 per cent better; if we were to re-evaluate now we think they would return to about the level they were at the time of Panel 6.

Q. All right. And given the current situation what is your view as to whether the range of approvals requested with respect to the hydraulic option is still appropriate?

A. We still believe that the range of approvals for the hydraulic that we are requesting is appropriate; that is, 1,400 to 1,800 megawatts of capacity and associated energy of about 3-1/2 terawatthours.

This is still appropriate because we have made relatively little change in the hydraulic plan since the evidence we gave on Panel 10, and at that time I gave four reasons for seeking hydraulic approvals. They were included in the transcripts at Volume 150, pages 26463 to -4. I believe they still apply. I won't bother to repeat them here, but one of them was that the hydraulic approvals add to the diversity and flexibility of the plan. We believe that is still an important factor.

MR. B. CAMPBELL: Mr. Chairman, that would be an appropriate time, given that we are about

at 10:45.

THE CHAIRMAN: We will adjourn now for 15 minutes.

THE REGISTRAR: Please come to order. This hearing will recess for 15 minutes.

---Recess at 10:45 a.m.

---On resuming at 11:04 a.m.

THE REGISTRAR: Come to order. Will you please come to order in the back of the room, please. Please be seated.

THE CHAIRMAN: Mr. Campbell?

MR. B. CAMPBELL: Mr. Chairman.

Q. Mr. Snelson, the materials filed in Exhibit 796 indicate that in December the Ontario Hydro board made a decision to issue a notice of termination pursuant to the Manitoba contract. As was pointed out, that was done on December the 17th.

It is clear from the materials filed that Hydro sought a five-year deferral of the contract originally from Manitoba Hydro, and perhaps just by way of some brief background to the cancellation I [illegible] ask you to outline the response that Ontario Hydro received with respect to the deferral proposal.

MR. SNELSON: A. There was an approach made to Manitoba Hydro to seek a five-year deferral of

the contract, and they did respond prior to the December board meeting, and they wanted compensation in a number of areas.

First of all, they wanted compensation for the change in the present value of the benefits of the contract to them. So if the contract is deferred five years into the future even if the benefits in real terms were to remain the same, then they would be subject to five years of discounting to bring them to a present value sense, and they wanted compensation for that.

In addition, they wanted compensation in the form of interest on the money that they have spent to date for a five-year period corresponding to the period of deferral.

Another area where they wanted monetary compensation was that they wanted a fee for what they termed -- and the words here are not that precise. They saw a degree of exclusivity in the contract for which they wanted compensation. This was to cover what they saw as a lost opportunity in that while this power was reserved for Ontario Hydro they were not in a position to seek a beneficial sale of that power to another party, and they wanted a monetary compensation for that, and that is a form of compensation that will

be -- the original contract reserved that power for Ontario Hydro, but there was no fee for that, and they wanted an additional fee for any deferral to cover that.

In addition to the monetary items they wanted tighter contract terms that would make it more difficult for Ontario Hydro to cancel or defer the contract, defer the purchase at a future date.

The total of the monetary items in today's present value would have been of the order of $300 million, and they would have wanted that money paid on the signing of a revised contract.

Now, these terms were not acceptable to Ontario Hydro.

Q. And I take it that led to the cancellation of the contract, and again perhaps just briefly if you could give the major planning considerations that affected that decision.

A. With a deferral not looking attractive, then the question was: Do we proceed with the contract on its original schedule? And the contract -- the cancellation was pursued because of four basic reasons of factors that had changed since we discussed this previously on Panel 10.

Because of a number of factors that were

changing with respect to the west system and needs for transmission then there was a reduction in the other needs for the transmission through Northern Ontario associated with the purchase and the effect of that was that more of that transmission cost would be allocated as a cost of the purchase, and so that had the effect of tending to make the purchase look less attractive.

We have discussed that with surplus and increased amounts of surplus that avoided costs are lower, particularly during the period of surplus, and that tends to affect the cost/benefit ratio of the Manitoba Purchase, particularly during the early years of the contract period when the purchase is not needed from a capacity point of view.

The third reason relates to the financial pressures that we are currently experiencing, and I did indicate that we can afford -- we believe we can afford less in the way of investments in the 1990s for long-term improvements, and the purchase requires transmission that requires a substantial investment in the 1990s, and that was considered to be less affordable.

The fourth reason is really a consequence of the other three, and that is that the upward pressure on rates that would result, particularly

during the first 10 years of the contract period, is no longer considered to be acceptable.

Now, it is not a new phenomenon. Dr. Long on Panel 10 did show a picture of the rate impact of the Manitoba Purchase, and that was page 100 of Exhibit 682. And while we haven't re-estimated that we would not expect that the rate impact to be any better than was shown in Dr. Long's figure.

But given the other factors, given the higher cost benefits estimated and the difficulties in affording the increments and the rate pressures that we talked about, it was no longer considered acceptable to bear that rate impact.

Q. Okay. I would like you to turn then to address the changes in the transmission situation, I guess spoken in general terms and more specifically how it is affected by the cancellation of the Manitoba contract, and I would ask you first to give us a sort of first order general description of the changes that are anticipated.

A. The transmission capital expenditures were part of the capital program review that was discussed in the October board memorandum, which was attachment A to Exhibit 796.

The specific assumptions at that time

included a five-year deferral of the Manitoba Purchase, and that memorandum shows a reduction in capital expenditures on transmission over the 10-year business planning period of up to $4 billion.

Now, that includes many items in addition to the Manitoba/Ontario interconnection. I would also caution you that that is in escalated dollars, and if you need the detail then the detail of how that is derived is shown in schedule 4 of the capital business plan guidelines, which was attached as attachment H to Exhibit 796.

With the information presented in this way it is not easy to relate it to our previous evidence on transmission, and so to try and remedy that we have prepared attachment I to Exhibit 796, which is effectively an update to Exhibit 442.13, which described the five interfaces, and I believe it was prepared in response to a request from Dr. Connell.

The basis of that attachment, attachment I, was the October decisions. It does not account for the December decisions. So it does not account for the Manitoba cancellation and it doesn't account for the new load forecast.

THE CHAIRMAN: I'm sorry, what is the last one?

MR. SNELSON: The new load forecast.

THE CHAIRMAN: Thank you.

MR. SNELSON: What is shown in attachment I is that a number of the plans have deferred in-service dates. That is to match lower short-term loads and to match the assumed, at that time, deferral of the purchase. Attachment I, however, does show maintaining the current approval processes for transmission.

MR. B. CAMPBELL: Q. Have the December decisions including cancellation of the Manitoba Purchase affected those transmission plans?

MR. SNELSON: A. Clearly, there will be effects on transmission plans. The full implications are not available at this time. They are being studied, and I think you will appreciate that the decisions were made a relatively short period of time ago.

[11:15 a.m.]

What is clear is that without the Manitoba Purchase, then the Manitoba/Ontario interconnection will stop, there will be no need for that route selection process, and as you have already heard, we have withdrawn our request for approval for the rationale and need for the Manitoba/Ontario

interconnection from this hearing.

Now there will likely be effects on other transmission plans. It will certainly affect at least the timing of some of the other plans and it may affect the scope. But the particulars of just how it will affect other transmission plans are not available until the results of the further study become available.

Q. I would like to turn then to you, Mr. Dalziel, and turn to consideration of the existing system, and I guess simply start by asking you to outline the components of the existing system that were considered in the course of the capital program review, what was contemplated in terms of that review.

MR. DALZIEL: A. There were two main components of the existing system that were considered in the capital program review. The first is the mothballing or early shutdown of existing units, and the second component is the deferring of planned expenditures for environmental controls.

Q. I would like you to outline each of these, highlighting the main considerations and decisions, and I would like you to start with consideration of mothballing or early shutdown of existing facilities.

A. In considering the mothballing and

shutting down of existing units, about 1,000 megawatts of fossil generation was considered, taking into account the Lakeview, Lennox, Nanticoke and Lambton generating stations, and it was also considered Bruce Unit 2 which accounts for about 800 megawatts, and also the early shutdown of the entire Bruce "A" station which would account for 3,100 megawatts.

There was an economic assessment that was done to determine the cost versus the benefit or the value of each of those options, and the details of that are described in attachment G of Exhibit 796.

Essentially, for each of these options Hydro determined the incremental cost attributed to keeping the unit in-service, and compared that to the value of the option using planning system incremental costs corresponding to the March 1992 values which were provided in Exhibit 592.

The results for this assessment for the shutting down or mothballing of existing generating units is shown on table 6-1 of Exhibit 796, and it is reproduced as page 12 in our package of overheads, Exhibit 937.

Essentially it shows that Lakeview is the only station for which there would be a net benefit to remove from service. The result was close to break

even.

For the other stations the results showed a significant cost if they are mothballed or removed from service in the near future.

I think the main point here, though, is that in terms of the economic ranking, if we were to removing a unit or station from service from the existing system, the first station that we should turn to would be the Lakeview generating station.

Q. And, in fact, have there been any decisions to mothball existing stations?

A. Yes, there have been. As a result of the Ontario Hydro Board of Directors' meeting in September there was a decision to remove from service beginning in 1993 two units at Lakeview, those are Lakeview's Units 3 and 4, and more recently at the December Board meeting, this was extended to include removing from service Lakeview Units 7 and 8.

These actions have been taken in recognition of the capacity surplus and the current pressure on electricity rates.

Q. How again does that compare with the managed surplus case that was discussed in the DSP Update?

A. The DSP Update has assumed, as part

of the illustrative surplus management, the removing of service Lakeview Units 3 and 4 beginning in 1994. So what we are seeing here are surplus management decisions that are going further and are taking place a little bit sooner.

Q. Now, you have touched on the economic assessment for ranking of options, was this method also applied for the ranking of demand management non-utility generation, hydraulic options, essentially all of those options that Mr. Snelson showed on the earlier overhead which I believe was page 1 of Exhibit 937?

A. Yes, a similar method was applied to the economic assessment of all of the surplus management options, and again that is described in attachment G of Exhibit 796.

Q. Now returning then to the existing system and the capital program review, you indicated that environmental controls were considered as well. Can you describe what was considered there?

A. As there were updates made to the short-term load forecasts throughout 1992, it was clear to Hydro that the load forecast, certainly in the short-term, was lower than earlier expected, and generally this translates into a lower use of the

fossil system.

So as part of the capital program review, Hydro looked at significant capital expenditures for emission controls on the fossil system that could be deferred. For sulphur dioxide controls this included scrubber units at Lambton and Nanticoke, for NOx controls this included combustion process modifications at Lambton as well as selective catalytic reduction at the Nanticoke station.

For particulate controls it included electrostatic precipitators at Lambton and Nanticoke.

Q. What was the purpose of that examination that was carried out?

A. The purpose of the examination was to look at a schedule of controls that would more closely meet the regulations and targets that Hydro currently has, and in doing so there was identified about $3 billion in capital expenditures that could be deferred over the next 10 years.

Q. Again that is still staying within all of the existing regulations?

A. Yes, it is.

Q. Have any actual decisions been taken yet on deferring emission controls?

A. No, there have not been any

definitive decisions taken.

The decision of the October 19 board meeting, of the board of directors, was to develop an emission control strategy, and this strategy would take into account more than just the hardware controls; for example, it would look at fueling options as well. But the intent is to develop a strategy that would be reviewed by senior management before making specific recommendations on a program of controls for the fossil system.

Q. So can you summarize then what the status is of this potential of up to $3 billion in deferred capital expenditures?

A. It's not possible to say definitively at this time whether all or some of that amount would be deferred over the next 10 years. Some of the control measures may go ahead and that again would only be determined after a review of the emission control strategy.

In the meantime, though, we are assuming a series of deferrals as an illustrative assumption in planning, and for reference, the deferrals that are being contemplated are described in table 6-2 of Exhibit 796, and that's found on page 16 of that exhibit.

All right. And given that illustrative set of deferrals about which decisions have not yet been made, have you done any analysis as to what emissions would look like if that illustrative program was in fact followed?

A. Yes, we have, and that information was provided to the Ontario Hydro board of directors at the time of the October board meeting, and it appears as figure 10 in the October board memo, and is reproduced in Exhibit 937 as page 13.

Now these results assume the load forecast and surplus management measures at the time of the October 19th board memo.

For reference, emissions corresponding to the DSP Update are also shown on this figure as the dashed line. Essentially what we see is that over the next 10 years emissions are generally below the projections that correspond to the DSP Update for carbon dioxide, sulphur dioxide and for NOx emissions. This is largely a result of the fossil system being utilized less, and there are two reasons for that: one is that the load forecast is lower over much of that period, and also there is a slightly higher amount of purchase non-utility generation that's providing energy in that time period as well.

After the year 2000, the emissions trend higher than the DSP Update, but they do remain less than the corresponding limits and targets.

I would like to point out that that if we take the DSP Update as a benchmark, then we still have time to develop definitive plans for the emission controls.

Q. So, in other words, in that sense there is no need to make those decisions today?

A. That's correct.

Q. I want to turn then to the requirement for major supply and major supply options, and staying with you, Mr. Dalziel, taking into account everything that has been said this morning, has Hydro re-estimated the need for new major supply using the December 1992 load forecast?

A. Yes, we have, and that has been shown as figure 8-1 in Exhibit 796 and it is reproduced here as page 14 of Exhibit 937. And this has been produced in the same way as we provided this type of information on Panel 10, and the corresponding figure in Panel 10 evidence was from Exhibit 682, page 28.

Q. Now, I think before we go any further, figure 8-1, page 14 of this exhibit is marked revised, and I understand that in producing Exhibit 796

on a fairly tight time schedule, an error was made in determining the load meeting capability at the back end of the planning period; that is, beyond 2015 to 2017 area, and I take it you have had time to correct that and make it consistent with the Update. Is all of that correct?

A. That's right. That's why this figure extends to 2017 which was the time period that was talked about in Panel 10.

Q. All right. Now, could you then go on and deal with what you wanted to deal with, with respect to this figure?

A. This figure is illustrating two things for us: One is the need date, and that is the time at which the planning firm load exceeds the load-meeting capability of the existing system, taking into account our priority and contract options. And we are showing the impact of the termination of the Manitoba contract as well.

The need date is 2009 without the Manitoba Purchase, and that is consistent with Panel 10 evidence. In Exhibit 452 we had described a need date as ranging from 2009 to 2011.

The other piece of information that this figure is illustrating is it indicates the new major

supply requirements to meet the gap between the load-meeting capability of the existing system and the planning firm load beyond those cross-over points on the far right-hand side of the figure.

Table 8-1 of Exhibit 796 itemized the new major more supply requirements to provide for those load-meeting capability needs, taking into account the 24 per cent planning reserve margin.

Basically, just to summarize, by the end of the plan period, the requirements for new major supply reach about 10,800 megawatts in the year 2017, that's without the Manitoba Purchase, and this is about 2,300 megawatts more than the requirements described by Panel 10.

If you want to compare the corresponding figure, it would be page 29 of Exhibit 682 in Panel 10's evidence.

Q. Is there any change to the major supply options which Ontario Hydro considers might be available to meet these requirements?

A. No, there is not. We think the major supply options available are the same as those described by Panels 7, 8 and 9. There may still be opportunities in the future to negotiate major purchases from neighbouring utilities. Essentially all

the fossil options as described by Panel 8 remain available, as do the range of nuclear options that were described during Panel 9.

There may also be additional NUGs or opportunities to purchase more energy from NUGs in the future which would work towards reducing the need for Hydro's new major supply requirements, and also there may be alternative nature technologies which may be able to make a contribution as was shown during Panel 10's evidence in the consideration of the enhanced case.

Q. Now, I notice that in figure 8-1 that you have been referring to, the load load-meeting capability exceeds the firm load forecast in the period 1992 to 2009, and I take it that that represents the capacity surplus over that period that we have been talking about?

A. Yes, it does.

Q. How has that capacity surplus changed since Panel 10?

A. The capacity surplus, the current projection of it was shown as figure 10-1 of Exhibit 796, and that's reproduced as page 15 of our current package of overheads. The main difference is that there is more surplus in the short-term; that is, more

surplus up to the about the year 1998. It's higher by about 1,000 to 1,500 megawatts in that period. Compared to the evidence of Panel 10, the corresponding comparison figure would be page 34 from Exhibit 682. Most of this difference is due to the load forecast.

The figure that we are looking at here on page 15 does not include Lakeview Units 7 and 8 which would reduce the surplus by 570 megawatts from about mid-1993 to the year 2007 when those two units would normally be retired.

Over that period, at least up to the year 2002 or 2003, that would reduce the surplus to between the 2,000 to 3,000 megawatt range.

Q. I take it that Hydro will be continuing to consider steps to manage the current view of surplus capacity?

A. Yes, we will. We would be continuing to review all of the options for managing the surplus, and that range of options is demand management, non-utility generation, the hydraulic options, as well as other units on the existing system.

As I said before during Panel 10 evidence, that we will continue to examine surplus management as part of the ongoing business planning process within Ontario Hydro.

Q. All right. Again, against all of that background, what do you see as the implications for the long term as a result of the December 1992 load forecast and the surplus management measures that have been taken to date?

A. We have had time to have an initial look at one illustrative system simulation.

Q. What did you include in that simulation?

A. What we have developed to carry out the simulation is what we call the load and capacity tables. Some of these tables may be familiar to you in the attachments of the Panel 10 witness statement, which was Exhibit 646, and these tables describe the plan components that have been described this morning, as well as it specifies the new major supply options that may be used to meet the new major supply requirements.

[11:36 a.m.]

We have been able to carry out an energy production run and then also look at the associated air emissions as a result of the energy production run.

Q. All right. Can you take these one at a time for us, please, and just indicate what the major supply additions are that were assumed?

A. The major supply additions assumed are illustrated in figure 10-2 of Exhibit 796 in the same way that we showed these major supply additions during the Panel 10 evidence, and the corresponding figures there from Exhibit 682 are pages 30 and 31, and it is reproduced as page 16 of our current set of overheads.

Essentially, we see new major supply units coming into service in the year 2010. There is a block of combustion turbine units in that year followed by a second group of CTUs in the year 2011. Also in the year 2011 we have the first unit of a baseload generating station coming into service.

The baseload generating station could be fossil or nuclear in the same way as we described in Panel 10. That would be IGCC units, integrated gasification combined cycle, or CANDU nuclear.

Q. Could you briefly run us through the energy production results, which I take it are shown on the next page.

THE CHAIRMAN: Could you perhaps explain, there is a revision of figure 10-2 from the original 796 with some additional supply factors you put in towards the end of the period. Could you perhaps explain that?

MR. DALZIEL: Yes, that's correct.

The figure that is in Exhibit 796 stops in the year 2015, and this figure goes on to the year 2017. Essentially, it is continuing to add major supply to meet new major supply requirements that we looked at earlier, just a moment ago, and the reason that it goes beyond those extra two years again relates to the error that we made in defining the load meeting capability in the earlier production of Exhibit 796. So had we got it right the first time you would have been looking at this figure in Exhibit 796.

What is happening then beyond the year 2015 is --

THE CHAIRMAN: And this figure does not also include the Lakeview decision; is that correct?

MR. DALZIEL: That's correct, but the Lakeview decision would not impact on this figure in that new major supply has been added only after the surplus has disappeared.

THE CHAIRMAN: All right.

MR. DALZIEL: You wanted me to go on to the energy production results?

MR. B. CAMPBELL: Q. Thank you.

MR. DALZIEL: A. The details of the energy production -- or there is more information on

the energy production results in attachment J of Exhibit 796. The main figure has been reproduced as page 17 of Exhibit 937, and again this is extending to the year 2017. In attachment J you will find this figure ending in the year 2015.

I will just summarize the energy production results by the end of the planned period.

Ontario Hydro-driven demand reduction reaches about 15 terawatthours. Of course, this is not really an energy that is produced; it is an energy that is saved. Purchase NUGs by the end of the planned period reach about 30 terawatthours per year.

Just to put those two numbers into perspective the typical use of the hydraulic units on Ontario Hydro's system today is in the range of 35 terawatthours. So demand reducing options are providing about 40 per cent of the current use of the hydraulic system and purchase NUGs would be providing about 85 per cent of the current use of the hydraulic system.

Moving down, I am working my way down from the top on this figure, and the next block is the existing fossil system. It is providing about 10 terawatthours per year throughout most of the 1990s. Beyond the year 2000 and the next decade it is

providing about 25 terawatthours per year. And after the year 2010 the existing fossil system is providing about 40 terawatthours per year.

New supply, the new major supply options would be providing about 45 terawatthours per year, and most of that energy would come from the baseload units as opposed to the peaking CTUs.

The existing nuclear units would provide about 55 terawatthours per year by the end of the planned period, and it is declining at that time as a result of the retirement of existing nuclear units.

Energy from hydraulic facilities would total about 40 terawatthours per year by the end of the planning period.

Q. Now, against that energy production can you highlight the air emissions, which I believe are shown on the next page, page 18 of the exhibit?

A. Once again on page 18, Exhibit 937, the reference to "revised" in the title of the figure is referring to the factor that it goes to the year 2017.

For SO(2) emissions, which is the top figure, I'll just quickly give you a little bit of background as to the environmental controls that are assumed. There are scrubbers on two units at Lambton

that are in-service by 1995, and then as they are needed there are eight pairs of scrubbers installed at the Lambton and Nanticoke stations over the years 2009 to 2015.

The light line on that figure corresponds to the DSP Update so that we can compare to the Update.

The boxed line corresponds to this illustrative plan with IGCCs as the baseload units, and beyond 2010 the dashed line below the boxed line is the emissions that would result if the baseload new major supply requirements were nuclear.

Essentially what we see is that for the SO(2) emissions regulations are met in all years with an adequate margin, and it is at least 25 per cent below the margin up to the year 2010.

For looking at the middle figure, the nitrogen oxide emissions, combustion process modifications for NOx control at Lambton units are assumed to be in-service by 1996. There are three pairs of selective catalytic reduction units at Lambton and Nanticoke stations installed around the year 2000. An additional four pairs of SCRs are installed at those stations between 2009 and 2015.

Again, we are substantially below target to the year 2010 and about 20 per cent below the target

beyond the year 2010 for NOx emissions.

Q. I take it, however, reading the small print on the diagram that there is some expectation that that target will reduce in the latter period of the planning period?

A. That's right.

Q. CO(2)?

A. For CO(2) there are no emission controls. The results show that the emissions would be below the illustrative target to about the year 2010, and thereafter the level of emissions is strongly dependent on whether new baseload supply is CO(2)-emitting or a non-CO(2) emitter.

If it is a non-CO(2) emitter then it may be possible to hold close to the target beyond the year 2010.

Q. Right. Have you been able to do a detailed determination of electricity prices for this plan as shown on page 18?

A. No, we have not. The most current projection of electricity prices is that which has been shown in the October board memo, and within that board memo it is shown within attachment A on page 8 as figure A. That also happens to be attachment A of Exhibit 796, the October board memo.

Q. Similarly, have you had an opportunity to complete the calculation of system incremental costs for the illustrative plan that you have been discussing?

A. No, we haven't.

The system incremental costs have been updated since the March, 1992 addition which was Exhibit 592, and that Update referred to those as the November, 1992 values, and they have been provided as attachment D of Exhibit 796.

Those values incorporate the load forecast, the capital reductions and the surplus management measures that are consistent with the October 19th board memo.

And the overall result is that the system incremental costs are down in all years, but they do return to the level of the March, 1992 values by the end of the planned period.

Q. Now, you say they are down in all years. How much lower are they?

A. In the near term they are down by about 20 per cent. As I say, they do return to the March, 1992 levels later on in the planning period.

A comparison is provided in attachment D of Exhibit 796 as figures 1 and 2 in that attachment,

and the comparison is of the planning and project appraisal SICs for the March, 1992 values and the November, 1992 values.

Q. What are the main factors that have reduced the system incremental costs?

A. There are two factors that have worked to reduce the SICs. One is a lower load forecast, particularly in the near term, and the other factor is the deferral of air emission controls on the fossil system.

THE CHAIRMAN: I'm sorry, air emissions?

MR. DALZIEL: The deferral of air emission controls on the existing fossil system.

MR. B. CAMPBELL: Q. In summary then I would ask you to compare the current view of the planned components on the basis that you have described to the DSP Update as described by Panel 10.

MR. DALZIEL: A. A comparison is summarized and shown on table 10-1 of Exhibit 796, and we have reproduced that as page 19 of our package of overheads.

The column on the far left side is simply listing the major Demand/Supply Plan components. The next column is the current view of the plan corresponding to the December, 1992. The remaining two

columns are referring to the DSP Update as described by Panel 10 for both managed and unmanaged surplus.

Starting with demand management, it is lower than before, about 3,400 megawatts of demand management by the year 2000, including the effects of standards, and this is as has been described earlier by Mr. Burke and Mr. Shalaby. Of course, one of the big factors that accounts for the differences is the amount of fuel switching that takes place by natural marketplace forces.

The next item, non-utility generation, in the December, '92 view of the plan it is about 2,800 megawatts by the year 2000. That is the amount that is available if we want it. That is the amount that is, as I say, available unless there are further measures to manage non-utility generation.

The Manitoba Purchase, Hydro has retained the short-term purchase of 200 megawatts that runs from 1998 to 2003, but, as we have heard earlier, we have terminated the 1,000 megawatt purchase that would begin to come into service in the year 2001.

For the hydraulic additions, both the Mattagami and the Niagara projects, as indicated here Hydro has chosen not to significantly delay these projects. They are planned for about the same period

as they were in the DSP Update for the unmanaged surplus, and particularly for the Mattagami project it is roughly the same time period as was contemplated even under the DSP managed case.

On the other hand, the Little Jackfish and Patten Post projects, Hydro has chosen to indicate a deferral of these two options by about 10 years as a surplus management measure, and this is consistent with the evidence of Panel 10 for the DSP Update managed case.

There are no changes in the planning of the Ragged Chute. So there is no change with respect to that particular option since Panel 10.

In the area of life extensions there are no changes since Panel 10.

For removing units from service there are two units that have been removed from service as a result of the September board meeting and an additional two units have been removed from service as a result of the December board meeting.

The results of the December board meeting are not reflected in this table, so the total amount of units that are being removed from service is four, all of that in 1993. And compared to the DSP this is taking place a little bit sooner and to a greater

extent, but directionally it is certainly consistent with the surplus management measures as described by Panel 10.

For environmental controls, there are many deferrals as is illustrated in table 6-2 of Exhibit 796, but, as I said earlier, we will be waiting for a more definitive schedule of emission controls as a result of the review of the emission control strategy.

For major supply the needs and options are similar to the descriptions of Panel 10.

Q. Finally, then, if could I come back to you, Mr. Snelson, for just a moment I am just going to ask you to summarize what you see overall as the significant changes in the demand/supply planning as it has developed since Panel 10.

MR. SNELSON: A. I think to summarize it in almost one sentence it is that there has been significant change in the short term, over the next five to 10 years and a lesser change with respect to our longer-term expectations.

In the short term there have been cuts to operating costs and capital plans responding to the increased pressures that we have discussed.

The short-term situation has had some

effect on longer-term plans, and we do believe we have a reduced ability to afford to make capital investments in the 1990s for potential long-term benefits.

With respect to the long-term specifically, then you have seen the comparison that Mr. Dalziel has described, and the changes from the illustrative managed surplus case that we described in Panel 10 are not all that large. The most significant change is the cancellation of the Manitoba Purchase.

Coming back to the general thrusts of the plan, then most of the thrusts of the Demand/Supply Plan Update still apply.

Mr. Burke has described long-term load forecast and how in terms of primary load there is not a great change. We still end up with the situation where we have no need for major supply approvals at this time. We still have a plan that is relying upon demand management, non-utility generation and hydraulic to meet the needs over the period from now until about the year 2010, and we believe the response portfolio that we described in the Update and in Panel 10 is still appropriate.

[11:55 a.m.]

MR. B. CAMPBELL: Thank you.

Thank you, Mr. Chairman. That completes

the direct evidence of this panel.

I think there are two matters which I wish to address just briefly.

The first is to advise you that I believe this brings the evidence before this panel in respect to the matters that have been considered by Hydro over the course of the fall as up-to-date as it is possible to be, and the ability to do that and present it to you so early in January has in no small measure been the result of great efforts on behalf of this panel and the staff that works with them over the course of the late fall, at a busy time of year in all circumstances, but they certainly have made significant efforts to bring all these events up-to-date for you, and I wish to have their effort recorded here.

The second matter which I wish to address is that I am unclear as to, on the basis of the odds and ends of correspondence and discussion that I have had with intervening parties, as to whether there is any request outstanding that cross-examination of this panel be delayed in any respect. If any one is going to make such a request, I would simply ask that it be dealt with now. As I say, I have some sort of whiff of this but I don't have good enough information, and the time since the new year has not permitted me to gather

good enough information to deal with any explicit request. But I would ask that the panel and certainly those of us who rely on advice from the panel to make sure that we don't make terrible mistakes in this case, that the panel not be put in a position where cross-examination be broken for any length of time.

If there is going to be any request, I would ask that it be dealt with now. Thank you.

THE CHAIRMAN: Perhaps we could see if anyone, I know there are some, who wish to ask questions of this panel as a result of the evidence here this morning.

Mr. Shepherd, I know you are one. You wish to ask some questions.

Anyone else?

Mrs. Mackesy.

MR. R. WATSON: The MEA will be cross-examing this panel.

THE CHAIRMAN: The MEA.

MR. CASTRILLI: Moose River and Nan/Treaty #3.

THE CHAIRMAN: Northwatch, Mrs. Smith, AECL, Energy Probe, AMPCO, CAC, CEG, ONGA.

I can't identify you, sir.

MR. ANSHAN: CAESCO. Mark Anshan,

CAESCO.

THE CHAIRMAN: Thank you.

SESCI.

MR. GRENVILLE-WOOD: The Sierra Club as well.

THE CHAIRMAN: Mr. Thompson, were you up. I didn't pick you up. Thank you.

Perhaps we could adjourn now and we can work out with Ms. Morrison, who is here, what the order of cross-examination will be, starting at 1:30 this afternoon. We start at 1:30 and go through until three and then we start again tomorrow morning if we are not finished in the hour and a half.

MR. STARKMAN: Microphone, please.

THE CHAIRMAN: Sorry. We will adjourn now and those who wish to cross-examine can work out with Ms. Morrison the order of cross-examination, and we will adjourn and come back at 1:30 and start the questioning, and continue tomorrow. If we are not finished tomorrow, we will not be sitting on Thursday this week. We will adjourn now until 1:30.

THE REGISTRAR: Please come to order. This hearing will adjourn until 1:30.

---Luncheon recess at 12:00 p.m.

---On resuming at 1:30 p.m.

THE REGISTRAR: Please come to order. This hearing is against in session. Please be seated.

THE CHAIRMAN: Mr. Rogers?

MR. ROGERS: Thank you, Mr. Chairman.

CROSS-EXAMINATION BY MR. ROGERS:

Q. Gentlemen, I have a few questions and I think if we could all have before us your Exhibit 937 that you filed this morning, we could perhaps use some of your charts to help us.

I understand from the evidence this morning, in fact, I think it was in your prefiled material as well, that Ontario Hydro now recognizes that market forces will cause more fuel switching from electricity to gas than you formerly thought to be the case.

MR. BURKE: A. Yes.

Q. And this is because, Mr. Burke - you are the delegate I guess to answer these questions - this is because the price of natural gas is now forecast to be favourable relative to the escalating cost of electricity in the long term?

A. Yes. As I pointed out in my direct evidence, though, I think there has been a favourable relationship between gas and electricity for some time.

Q. Yes.

A. But I believe that the reason why we needed to make an adjustment to the forecast in response to the events of the last two or three years was it has only been in the last two or three years that there has been a significant shift in response to that price differential by electricity customers.

Q. Yes, you did say that. And the table that you referred to while making those comments this morning was page 2 of Exhibit 937, I think. Wait a minute. Sorry, that's the wrong one. It's page 4, right, Mr. Burke?

A. Yes.

Q. And we see there that, yes, indeed, natural gas has enjoyed a price advantage over electricity according to your calculations over most of the recent history except for a little period there in 1981 to '83 or so; right?

A. No. The plot indicates that there was price advantage in that period, though it was at its narrowest at the point. It was fuel oil that exceeds.

Q. You are quite right. So it's always had a distinct advantage.

A. Yes, in pure price terms, yes.

Q. Now, why is it, if that is so, that

people didn't respond logically and switch to natural gas?

A. Well, the gas, the space heating market has been essentially split in Ontario between areas where gas was available and where it was not available, and gas has had the majority of the market share in areas where gas was available, but in areas where gas was not available, electric space heating competed directly with fuel oil. And I think with the OPEC crisis in the early 70s, there was a fair bit of uncertainty about the role of -- well, the price prospects for oil, and that encouraged people to choose electricity in a non-gas available areas, and also the gas price was seen to be tied by many people to the price of oil and the prospects for oil prices and so there was uncertainty about the future for gas prices because of the connection of gas pricing to oil pricing.

Q. Well, is your answer then that the reason that people didn't act rationally is because they falsely assumed that gas would be tied to oil and that there was going to be a lot of uncertainty about its price?

A. I think there will always be a relationship between gas prices and oil price in key

markets, but yes, I think a lot of it did have to do with the uncertainty associated with future prices.

Q. That was spawned in the early 70s during the oil crisis?

A. Yes.

Q. That is a long time ago. Why suddenly now has the public come awake, do you think?

A. Well, it was only in 1986 that the OPEC cartel power really diminished in the world marketplace and oil prices crashed. And I think while gas prices never reached the peaks that oil did in terms of absolute amounts and also in timing, that is the price of gas peaked in Canada in about '83 as that plot shows, the price of gas has weakened for some time.

Q. Well, I still am not very clear. I don't want you to repeat what you told me. If that's your answer, fine. But have you anything else to help us understand why it is Ontario Hydro now realizes that people are switching to natural gas in response to this favourable price relationship?

A. Well, I can only repeat what I said in my direct evidence, that the data we have on fuel switching just says that until 1988 or '89 there was very little evidence that people were doing it. Why

they were not doing this before, I really can't say.

Q. You don't know. One thing we do know, and that is from looking at your data here that the pure price differential alone isn't enough to make it happen; is it?

A. Well, I think the pure price differential, certainly when it gets to the extreme that it has reached today may be much more -- may be able to overcome people's concerns about future price uncertainty.

Q. Maybe. But even if we look at these data, historically there was a distinct price advantage and yet your data shows that people were not switching in the numbers that logic would dictate ought to have switched; isn't that obvious?

A. I think that the choice of a heating system is a long-term decision and I think the observed prices are not the basis on which people were making that decision.

Q. Thank you. So the basis on which people were making a decision then was heavily influenced by the capital cost of the furnace, for example, that they would install when the house was built; right?

A. It's one factor in the decision.

Q. And that's still a factor in the decision?

A. Yes.

Q. You may recall - I think it was you - discussing with me earlier in the hearing some months ago a program that the government introduced to deal with this very problem and I think it was in the public housing sector. Are you familiar with that program?

A. In general terms only.

Q. Perhaps it wasn't you.

MR. B. CAMPBELL: It was probably Ms. Fraser.

MR. ROGERS: Maybe it was. I will try to recount what I believe the gist of the discussion was.

Q. My recollection is that the government introduced some type of mandated policy which required the use of natural gas where available in certain government housing.

Are you familiar with that, Mr. Shalaby, that program?

MR. SHALABY: A. I was on that panel, yes.

Q. Were you? Good.

Have I fairly stated roughly what that program did?

A. In general terms, yes.

Q. And I think the witnesses told me at that time that that was necessary because even though there was a distinct advantage from a price standpoint for natural gas over electricity, it was necessary for the government to provide some impetus to people so they would not be unduly influenced by the upfront capital cost of the furnace. Do you recall that?

A. Yes, I follow it.

Q. This is a pretty simple point. People who are buying a new home may not have the choicie themselves for one thing, it may be the builder who chooses the type of heating; correct?

A. Yes.

Q. And the builder, because he wants to sell the house, is going to be more heavy influenced by the capital cost of the furnace rather than the long-term cost of the energy that goes into the furnace; correct?

A. Yes.

Q. So that there is a bias if the capital cost of electrical furnacees is lower than the capital cost of a gas furnace, there is a bias that would lead to the decision being taken to have electric heating even though it may be uneconomic in the

long-term; correct?

A. There is a bias that lowers first cost for the bidder, yes.

Q. Right. So the builder may choose what in effect is an uneconomic choice for the ultimate consumer.

A. They may, yes.

Q. In fact, if left to their own devices I would think they would; would't they?

A. Well, unless if consumers come and demand gas heated homes, they would do the other thing.

Q. And for the consumer to do that, the conusmer would have to be sufficiently knowledgeable and logical and wealthy to be able to afford the higher cost of the gas furnace at the outset because that consumer would know over the long run he would yield net savings.

A. There are many aspects of a home that fall into that category.

Q. We are just talking here about energy at the moment, though.

A. Okay. Insulation, for example, is such an example.

Q. Yes, I suppose it would be.

What is Ontario Hydro planning to do, if

anything, to make sure that the appropriate decision is made in the beginning so that this economic fuel switching does in fact take place and continue to take place as you have forecast?

MR. BURKE: A. I think the point in the load forecast is that the fuel switching is taking place, at quite a rate in the areas where -- and we are talking now conversions of existing systems, where people are replacing systems or considering alternate heating systems where they have a central electricity furnace already, so the front end cost is not very different between the two options, they are choosing gas now because of its lower operating costs. That is the major change in the forecast that central electricity furnaces are converting.

Q. Right. You quite correctly pointed out that all you are doing is telling the Board what you have observed in the data but my question is and perhaps it shouldn't be addressed to you Mr. Burke, maybe Mr. Shalaby or one of the other panel members, but what do you think it might be appropriate for Ontario Hydro to do, short of spending your money, because you said you don't want to do that any more, to encourage that type of conversion.

MR. SHALABY: A. I think what we

indicated was the provision of adequate information to consumers as to what the fuel choices are and what the advantages are and what the disadvantages are.

Q. Can you help me a little more as to what exactly you propose to do to ensure that that type of information is in the hands of consumers?

A. I am not familiar enough exactly with the plans for alternate fuel information that will be provided.

Q. Are there any plans available at the moment, do you know, or is this in the planning stage?

A. I am not familiar enough with the specifies at this time.

But we have seen in this hearing, for example, the Ontario government has brochures about heating choices, water heating and space heating choices about gas and electricity oil. So that kind of information is widely available to the public in various forms.

Q. Tell me, Ontario Hydro has had situations of surplus capacity before?

A. Yes.

Q. When was roughly the last time when you had a large surplus?

A. About 10 years ago.

Q. That would be right after you looked at the whole question of marginal cost pricing I guess you developed that surplus?

A. Not because of that I don't think.
[Laughter.]

Q. It I recall correctly, it was in the middle of that hearing?

A. I think it was subsequent to that, yes.

Q. Do you think it's a valid concern that Ontario Hydro --

A. Is seems you start a hearing and three years later you get surplus. [Laughter.]

Q. Certainly on the basis of my experience. That's very predictable [Laughter.]

How do you answer the concern that some may have that Ontario Hydro will tend to soak up this surplus capacity you have now by marketing peak load space heating as I believe you did the last time around?

A. Your question is how do I...

Q. Can you assure the Board and people in this room that Ontario Hydro will not engage in programs designed to, in effect, market demand to soak up this excess capacity that you have?

A. Marketing electric space heating is unlikely to occur. That's definitely not in the current plans.

Q. That would certainly --

A. It goes against all that we worked for over the last several years in terms of appropriate choice of fuel for appropriate use and an energy efficient Ontario.

Q. Yes, I agree. But am I not correct, sir, that the last time Ontario Hydro had a major supply surplus that it, in fact, did just that?

A. Yes, you are correct.

Q. I know you can't speak for the whole corporation, although you are in a position where you sort of have to, but can you assure us insofar as you are authorized to do so, that Ontario Hydro will not do that this time?

A. Yes.

Q. And Ontario Hydro will use its influence with the municipal utilities to see that they do not that this time insofar as you are able to do that?

A. Insofar as we are able to. As you well know the influence on municipal utilities works with some of them but not with all of them.

[Laughter.]

Q. No, I understand that.

[1:45 p.m.]

Thank you very much. I suppose the government can help in this regard as well, couldn't they?

A. Yes. And that could be a difference between the current situation and the earlier time in that there was a big thrust off oil and gas at the time, the late '70s, early '80s. So the substitution into electricity was in fact a government policy off oil and gas.

So the situation is exactly not analogous to what it was. There is surplus, but there are many other things that are different.

Q. All I am saying is that you would encourage the government to exercise its influence to ensure that the surplus is not soaked up by marketing electricity in competition with gas.

A. For space heating and water heating we don't feel that is an appropriate use for electricity.

Q. Now, just one last small area of inquiry here, and that is to help me understand just where it is we are now in this hearing. I know this is

going to be the subject of a lot of discussion later on, but help me if you would.

I know that Ontario Hydro now has before the Board a request for approval for some hydraulic facilities. Mr. Snelson?

MR. SNELSON: A. We have a request for approval of a range of hydraulic capacity and energy.

Q. Yes. And you have also shown us this morning - and this was in the prefiled material as well; this is at page 16 of Exhibit 937 - that by about the year 2010 it is now proposed that the new major supply will be added to the system...Mr. Dalziel, is it?

MR. DALZIEL: A. Yes, that's right.

Q. You have also said this morning, I think, that 659 megawatt baseload increment in about the year 2011 could be nuclear?

A. It could be nuclear it, it could be fossil.

Q. What is the present planning horizon for nuclear facilities as Hydro sees it?

A. What do you mean by 'planning horizon'?

Q. If you are going to build a nuclear plant in 2011, have it ready to come on stream in 2011,

when do we have to start work on that project to get the approvals and so on?

MR. B. CAMPBELL: Mr. Chairman, this was an area that was gone into in great detail. The evidence of this panel is that there is no change in that area with respect to the nuclear facility -- nuclear evidence given by that panel, and in my submission it is beyond the scope of what this panel is here to do. That was gone into in great detail.

THE CHAIRMAN: I think you will find the answer in that evidence.

MR. ROGERS: Thank you, sir.

THE CHAIRMAN: You can pose a hypothetical question if you want in order to assist.

MR. ROGERS: If I could help the Board, I don't plan to challenge this at all. I just want to back up and find out where it falls in the 25-year planning period that we started looking at when we began this hearing. That's all.

Q. So can you help me, gentlemen? I just don't remember what the answer is.

MR. DALZIEL: A. With respect to the --

MR. B. CAMPBELL: Just a minute.

MR. ROGERS: Sorry, Mr. Campbell. I thought that would solve your concern.

MR. B. CAMPBELL: No. Mr. Chairman, I intend throughout this cross-examination that we will take a fairly firm line, what we are here to do is speak to the specific changes that we were asked to address when we called this panel. And for whatever purpose, I don't care what purpose it is, in my submission it is inappropriate to go back over areas where there is no change, and the evidence is clear on that point, and for whatever purpose this is not just another opportunity to continue cross-examination of matters that have already been covered.

THE CHAIRMAN: I think I agree with Mr. Campbell's submission in general, but perhaps you could still frame your question so it wouldn't offend Mr. Campbell.

MR. ROGERS: That is a nearly Herculean task. [Laughter.]

THE CHAIRMAN: What you really want to know is whether there is enough lead time to bring on stream a new major nuclear capacity of 659--

MR. ROGERS: Yes.

THE CHAIRMAN: --megawatts by the year 2011.

MR. ROGERS: I just wanted to know when we have to start thinking about that. That is really

what I want to know. If it takes about 10 years or so from start --

THE CHAIRMAN: Well, I think you will find the answer to that in Panel 9.

MR. B. CAMPBELL: Absolutely.

MR. ROGERS: Okay. Well, if it is there it is there. I won't push it if it is in the evidence. Thank you, sir.

Q. What the data has told us then, I gather, Mr. Burke - just to return to the previous point, then we can finish this off - is that people are now switching to natural gas because of the price advantage; right?

MR. BURKE: A. Yes.

Q. One would expect that to logically happen?

A. No. I think that you already pointed out that there is a long period there where it didn't happen and then it changed, and, therefore, there must be something other than the fact that there is a price differential.

Q. Price is an important part, but there are other factors as well. Fair enough?

A. Yes. But also there is a stability to the price, a perceived stability to the current

price differential which did not exist before.

Q. And the other thing that we have to have for this to work, for market forces is to work is that you have to have the prices set at the appropriate levels to reflect the true cost?

A. I'm not sure I follow -- is that a question?

Q. I thought it was.

A. You are asking me if for this to work the prices should be set --

Q. If you are going to have an efficient switching from one fuel to another the prices of the competing fuels have to be set properly. Isn't that obvious?

A. Well, it depends what you mean by 'efficient switching', but if what you mean is that the optimal amount of switching occur in some theoretic economic sense then I think the price of natural gas is certainly set efficiently in the marketplace right now. I don't have any concern with that. And the price of electricity is set on the basis that it has been set by regulators for many years. Effectively, we have efficient prices in the marketplace.

Q. So that is your way of saying "yes"?

MR. B. CAMPBELL: His answer says what it

says, Mr. Chairman.

MR. ROGERS: Okay. Thank you very much. Thank you, sir. Those are my questions.

THE CHAIRMAN: Thank you, Mr. Rogers. Mr. Castrilli, you are next.

CROSS-EXAMINATION BY MR. CASTRILLI:

Q. Could I ask you, gentlemen, to turn to what would be attachment C of Exhibit 796. We will be looking at page 5.

As I understand your testimony generally, long-term demand is driven by both energy prices and gross domestic product, and can we take it that the latter factor is greatly influenced by population growth?

MR. BURKE: A. Yes.

Q. Now, just looking at page 5 - and I believe this was referred to in the oral testimony this morning - looking at paragraph 3, you note that there is going to be a boost to population growth of an additional 500,000 people expected to be living in Ontario by the year 2015.

Can you indicate what the source or what information base you are relying upon to justify a projection of a half a million people more by 2015?

A. The demographic projection that

underlies the economic outlook that underlies this load forecast was prepared by our Economic Forecast section and is in keeping with the current consensus of the Treasury and Economics Ministry, Statistics Canada that fertility rates are somewhat higher than previously expected and that immigration rates to Canada in the long term will be higher than we had included in the forecast previously.

Q. Can I take it that the 500,000 is taken directly from a Statistics Canada projection?

A. No, it is not. We prepare our own demographic projection, but the various components of that projection use assumptions that are quite acceptable and of a consensus nature in the demographic community.

Q. Would it be fair to say that for some of your projections such as information relating to your econometric model and for energy data you take information for purposes of input in respect to those two items directly from Statistics Canada?

A. For forecasting purposes the forecasts we use are all generated internally. Statistics Canada itself prepares no forecasts.

For demographics they prepare scenarios. We do not use their prepared scenarios. But they don't

prepare any other forecasts that I am aware of.

Q. Do you know whether your 500,000 people by the year 2015 is in fact a projection that is higher than Statistics Canada's for the year 2015?

A. Off hand I can only tell you that Statistics Canada produces various scenarios with various sets of assumptions, and the projection we have now is very close to what our own treasury and economics, sort of government projection is for Ontario, and there is probably a Statistics Canada scenario very similar to the one that we use right now.

They would also produce other scenarios just as they are, scenarios.

THE CHAIRMAN: When you refer to "treasury and economics", you mean the Ontario government?

MR. BURKE: Yes.

MR. CASTRILLI: Q. We will now move to what would be or what is Appendix 2 of attachment C in the same exhibit, 796.

MS. PATTERSON: What was that again?

MR. CASTRILLI: Appendix 2. It is actually a separate document that is a part of attachment C in Exhibit 796.

Q. We are looking at again -- sorry, we

are looking at page 5, table 2.2. Let me know when you have the page.

MR. BURKE: A. Page -- table 2.2?

Q. Yes.

A. Yes, I have that.

Q. This is the Ontario real domestic product in 1986 dollars in millions?

Now, I just wanted to understand what is going on in this table.

As I look at this table, and I am looking now at the years in particular 1993 and 1994, growth rates have been increased from 4.0 and 4.5, respectively, to 4.6 and 5.0 per cent, respectively; is that right?

A. No.

Q. No?

A. I think you have caught us in a typo here. The numbers -- sorry. No. What has happened -- yes. Sorry, take it back. No.

The forecast was reduced in 1992 in July and increased in 1993 in July and also in 1994. So you can see that the 1992 forecast made in November, '91 was 3.9 per cent. It was reduced 1.3 per cent or so to 2.5. Then, effectively the growth taken out of '92 was built back into '93 and '94 in the economic forecast

prepared in July. That forecast has subsequently been revised down again.

Q. Let me come at this a different way, Mr. Burke, if you are finished.

A. Yes, I am.

Q. What information are you relying on to justify these increases in growth rates?

A. The short-term economic forecast prepared by Ontario Hydro is a consensus forecast. We discuss this with the Ontario Energy Board every year, and Ontario Hydro uses a large group of forecasters to get a consensus forecast for Canada and then develops an Ontario forecast that it believes to be consistent with that consensus for Canada.

So the numbers you see here are the result of that process.

Q. How would the short-term forecast change if the assumptions used in the 1991 forecast were incorporated into the forecast for the years 1993 through 1996?

A. Sorry, how would the load forecast change, is that the question?

Q. How would the forecast change for that four-year period?

A. The economic forecast or the load

forecast? I'm not sure which forecast you mean.

Q. The forecast we see in table 2.2. And also, how would the overall load forecast be affected if you used the 1991 forecast -- sorry, the 1991 forecast percentages instead of what we see for July, 1992 for the period '93 to '96?

A. Well, perhaps -- if we go back to the main attachment C there is a section on economic forecast there, which is on page 16.

It gives the November, 1991 numbers that you are talking about as the numbers that were used last year in the DSP Update forecast, and it also gives the numbers we have used this year.

For '93 to '95 you can see that they are the same in '93 and '94 and that '95 is 1 per cent higher this year than last year. But again, it is '92 that is down considerably.

I guess what I am trying to say is you can see the results of the growth rates at least for '93 and '94 in the forecast we have got right now.

Q. All right. Let me turn to page 7 of the Appendix 2, and we are looking at the very last sentence -- sorry, the last two sentences on the page, which say:

The new level for 1992 load was not

taken directly from any of the models or the customer forecast but was a combination of the three. For 1993 to 1997 the annual model error correction provided the basic energy rates of increase.

Can I interpret that, Mr. Burke, to mean that the customer survey results were not used in any way for any forecasts beyond 1992?

A. First of all, we are talking here about the July, '92 forecast, which is not the short-term forecast, which is not the forecast in evidence before this Board. It has been superseded by the October short-term forecast which is discussed later in the appendix.

[2:05 p.m.]

But for the record, we certainly did look at the values that the customers provided us beyond 1992 when we prepared the July forecast.

Q. Looked at but didn't use directly; is that right?

A. That's correct, yes.

Q. Now, on the same page, page 7, in the first paragraph, again the last two sentences read:

Tests done on the state space model

with actual data in various time periods show that it reacts strongly to recent changes in pattern and growth. Due to its response, its projections are to be tempered by judgments in times of rapid but transient change in pattern.

If you would you just bear with me for a moment, Mr. Burke, I would like you to also look at page 15 of this appendix. The third paragraph, the third sentence says that:

The state space model forecast of 0.7 per cent was rejected as not sufficiently responsive to the economic recovery projected for 1993.

And so instead 2.0 per cent was used.

Can you clarify for the Board why it was you used 2.0? And, in particular, is the statement at page 7 of Appendix 2 that I read into a record a moment ago consistent with the statement on page 15 that I just read?

A. Yes, I think the statements are consistent. And essentially, the state space model is currently influenced heavily by recent history and has a very weak projection for load growth.

Because there has been a -- the

relationship between GDP has not been a typical historical one, there is a very weak relationship in that model to GDP, a relationship between GDP growth and load growth. And so when we were forecasting a recovery in the economy for 1993, the model was not picking that recovery up, it was not effectively taking our forecast of economic recovery seriously. And so we chose not to use the model as we were going to believe the economic forecast that a recovery would take place in 1993.

Q. Could I ask you, we are still in attachment C, ask you to go to page 83, we are looking at the table on this page. As I understand this table, correct me if I am wrong, it indicates that the 1989 to 2000 average total industrial growth rate is assumed to be 2.1 per cent per year, which I take it is derived through construction of industry by industry process level models, is that...

A. That is a fair description.

Q. Is that fair?

A. Yes.

Q. Now, I also noticed on this page there is a category called "other", which is pegged at 6.7 per cent. I take it somewhere else in the text there is a discussion of what are the other industries,

but for the record could you just advise the Board quickly of what the principal ones are?

A. Well, there are a number of small industries, but the key issue concerning other is contained in the text on bottom of page 81 and the top of page 82 where it explains that for the short-term forecast which is included in this '89 to 2000 interval, the other category which is the very top line of page 82, it says is used to make up the difference between the end-use forecast in the recommended short-term load forecast. Its strong growth may be interpreted as accounting for currently unspecified growth potential.

It essentially is used in this forecast to tune the end-use projection to the short-term load forecast. That's why it's so large.

I could hunt up the list of industries included in "other" if you wished. But without that sort of adjustment factor, it would have a growth rate probably pretty similar to the one it has between 2000 and 2015 where it is just running around 1 per cent.

Q. So clearly the 6.-- sorry, the overall 2.1 per cent average is pushed up considerably by the high rate assumed for the other category; is that a fair statement?

A. Yes, it is. But the methodology used in preparing the load forecast which is described in chapter 1, says that we produce the short-term load forecast first and then we tune our long-term models to the results of the short-term forecast, and this is the way this model is tuned.

Now there are some judgments in there, admittedly.

Q. Mr. Burke, just so I am clear, and you may have already answered this, and if you have I apologize. If the "other" category were forecast to grow at the same weighted average rate as the named categories, such as iron and steel, can we take it that the total industrial growth rate would be substantially lower or would be lower?

A. Yes, the difference in 1997 is 5 terawatthours to the level of the end-use forecast.

What is at stake here is whether the end-use forecast for the short-term is a better predictor of the short-term than the combination of methods that we have used to derive our short-term load forecast.

Q. And if you can give me a ballpark, if you haven't already, how much would the forecast of peak demand and energy be reduced for the years 2000 to

2015 if the "other" category was forecast to grow at the same weighted average as the named categories?

A. Well, I'm not sure they would have been forecast to grow at exactly the average, but if it was not adjusted, then the way the forecast was prepared, there would be a 5 terawatthour difference from 1997 right through the forecast period.

Q. Through to 2015?

A. That's correct.

Q. All right, thank you.

Now, could I ask you, Mr. Burke, to turn to page 87.

I am assuming if there are other witnesses who are more appropriately the person to answer the question, that they will not be reticent to do so.

Could I ask you to look at - for the timing being I will just focus, Mr. Burke - the next to last paragraph on page 87. The last sentence, actually, says:

> The possibility exists of shifting the highly electric insensitive electrolytic smelter to Falconbridge's Quebec smelters if hydro rates remain lower there.

Can you tell me offhand, Mr. Burke, how

much the load forecast be reduced for the years 2000 to 2015 if in fact this shift does occur?

A. I don't have the Falconbridge, that particular smelter operation's load here right now. And in fact, I am not sure that I would be able to tell you because I think that's a confidential piece of information.

Q. Just for the purposes of our discussion, I don't need it, this specific data, but can we take it that what follows, should that shifting actually occur, is that there would be a reduced load forecast for the period 2000 to 2015, all other matters being equal?

A. I like that caveat. All other things being equal, yes, the forecast would be lower if this plant moved to Quebec. It never is, though.

[Laughter.]

Q. Now, I think, Mr. Snelson, it was you this morning who indicated during examination in chief that Ontario Hydro has - I don't think I actually got this down verbatim - but Hydro has withdrawn its application or will be withdrawing its application for the requirement and rationale for the Manitoba interconnection as a result of the cancellation of the Manitoba Purchase contract; is that right?

MR. B. CAMPBELL: I think I spoke to that this morning, Mr. Chairman. Yes, Ontario Hydro has indicated it is no longer seeking approval of the requirement and rationale for transmission incorporating the Manitoba Purchase.

MR. CASTRILLI: Q. The other thing that was said this morning in connection with transmission is you said there was no information available as to how cancellation of the contract affects other transmission plans. Just so I am clear on this, you are not in a position at this stage to indicate to the Board whether Ontario Hydro intends to proceed with the construction of any east/west transmission for other purposes unconnected to the purchase?

MR. SNELSON: A. I believe the situation is that the current plan for the Manitoba/Ontario interconnection from northeastern Ontario to the Manitoba border will not be proceeded with.

Now, there may be other transmission, and there are other transmission plans in northeastern Ontario and in northwestern Ontario, but that major transmission line will not be proceeded with.

Q. What is the time frame we are all collectively learning about what other transmission scenarios might come forward?

A. I don't have a specific time frame, and it may be different for different transmission plans, but it will emerge over the next three months, I would expect.

THE CHAIRMAN: I think this morning you said it of the order of two months; is that right?

MR. SNELSON: I believe with the order of two months I used with respect to the hold on non-utility generation projects.

THE CHAIRMAN: That's right, I'm sorry.

MR. SNELSON: I don't believe I did mention a specific time for the transmission studies.

THE CHAIRMAN: That's right.

MR. CASTRILLI: Q. Now, somewhere in your overheads, let me see if I can find it very quickly. I believe it's around page 11 of Exhibit 937. Let me know when you are there.

MR. SNELSON: A. Yes.

Q. Mr. Snelson, we see in the middle of page 11 which is a protection of reproduction of table 5-1, schedule of hydroelectric projects, in the middle of the payable the resurrection of Little Jackfish, as it were, and can we take it that the resurrection -- I am sorry, the resurrection, the pushing back of the due date to 2009 implicitly carries with it transmission

plans at at some point in time?

A. I don't believe this is the resurrection of Little Jackfish. Little Jackfish has never been killed.

Q. I took the word "cancelled" to mean dead.

A. That was and illustrative assumption. At that time Little Jackfish was still proceeding and it was an illustrative assumption of how the surplus might be managed.

Q. I see. I will proceed cautiously when I see the word "cancelled".

If I can have your clarification on this, there will be, to the extent Little Jackfish remains on any kind of time frame, transmission associated with it?

A. There is clearly transmission from the Little Jackfish site to the nearest point on the bulk system, which is closely associated with the Little Jackfish project, and that would be affected by whatever schedule is decided upon for Little Jackfish.

Q. Could I ask you all collectively to turn to Exhibit 796, table 1.1. I think it is also page 1 of your Exhibit 937, for the record. As I look at this table, which is the economic impact of 10-year

project deferrals and mothballing, it seems to provide what I take to be an economic ranking of project deferrals for surplus management. Is that a fair characterization of what it is?

A. Yes.

Q. Now, bear with me because this information is sort of all over in this exhibit. I would like to you turn to attachment G, and we are looking at page 13, and this is figure 4.1, incremental benefit cost or cost of deferral, mothballing or retirement candidate demand/supply options for surplus management.

[2:25 p.m.]

Just looking down this page it indicates the retirement of the Lakeview units. Now, would that be all four units or is that just two units?

MR. DALZIEL: A. The analysis was based on four units, but I think the economic ranking applies to -- as I said in my direct evidence, when you turn to a station on the existing system and you want to remove units from service Lakeview would be the first station you would turn to, be it one, two, three or four units.

Q. And just looking at the Lakeview units column I think you will confirm for me that it involves a net -- sorry, that retirement of those four

units involves a net cost to Ontario Hydro of $42 million; that is to say, with a present value of $37 per kilowatt. Is that right?

A. Yes. The table is indicating that as a net cost, the $42 million. That is in the last column.

Q. Yes, that's right. And if we look up one column to Mattagami?

A. Before we go on to the Mattagami I would just like to point out there is an explanation for the...page 12 I believe it is.

The last paragraph on that page does note that while there was a cost associated or shown in table 4.1 for the mothballing of Lakeview units it was judged that with the knowledge that the system incremental costs were going downwards that if new SIC values were used, such as the November, '92 values, that we would in all likelihood end up showing a benefit for mothballing the Lakeview units. As I say, the note on page 12 describes it.

Q. I was going to come to that as well. I appreciate your pointing it out to me.

Let's just return to 4.1 for a minute on page 13. As I understand the table, deferral of the Mattagami complex would provide a net benefit to

Ontario Hydro of $11 million at a present value of $29 per kilowatt. Is that how we read that?

A. Yes.

Q. All right. Now, you have indicated in reference to page 12 that deferral of Niagara and Lakeview create net benefits where before using the previously available March, 1992 system incremental costs you had shown small costs, if I can put it that way.

Is that essentially what we have just been talking about?

A. Yes.

Q. All right. Now, let me come back to that, but before I do that I just want to ask you to turn to page 11 of the exhibit as a whole -- of 796, I should say. Let me know when you are there.

A. Yes.

Q. And we are looking at the bottom of the page. The next to the last sentence says: These new values - which are the values we have just been talking about - if applied to the hydraulic program would tend to reduce the long-term benefits of hydraulic options by about 10 per cent but would increase the benefits of deferring.

Perhaps you can just give me a clear

statement on this, as to why Ontario Hydro has decided to retire the Lakeview units while proceeding with Mattagami at this point in time.

MR. SNELSON: A. I think on the basis of economics these are all quite small numbers that we are talking about and the differences between the Lakeview units and Mattagami are in the area that we consider quite small.

And I believe that was -- I did discuss that in my direct evidence, and that we are continuing with the Mattagami project because of the other benefits of the project that we discussed in Panel 6 and Panel 10.

Q. On the basis of figure 4.1 we are looking at a $50 million differential. What are the new numbers as between Mattagami and Lakeview?

A. The change in system incremental values would affect both projects.

Q. Yes. So does that mean the differential stays the same?

A. Generally speaking, the change in system incremental values, as I indicated in my direct, for projects that have similar energy production characteristics that if we use a different set of system incremental values that we would end up with a

situation where the ranking would not change very much. And that is what I said in my direct.

Specifically, between Mattagami, which has a higher energy production I would expect associated with it than the incremental energy production from Lakeview units, I can't be quite so definitive on that.

Q. I'm sorry?

A. I can't be quite so definitive that the ranking won't change because of the differences in the energy production characteristics.

Q. Do we have someplace in the evidence and I just haven't found it what the new number -- what the new net costs would be, in effect an Update of figure 4.1 at least as it relates to Mattagami and Lakeview?

A. No, you don't have it.

Q. I'm sorry, were you done with your answer?

THE CHAIRMAN: The answer was no, they don't have it.

MR. CASTRILLI: Q. All right. Could I ask you -- I think we had been discussing page 11 of Exhibit 796 a moment ago, and as I understand this page it indicates that the preliminary recommendation for

Hydro to defer the Mattagami complex by six years was reversed owing to benefits in addition to economic benefits that had been identified by Ontario Hydro.

And as I understand it, they are sort of summarized in what would be point 4(e) of the Executive Summary that is part of attachment A? And that would be the second page of that attachment.

In particular you identify better operational utilization of the river, improved reservoir and erosion management, regional development, and relatively low cost upward flexibility.

Do you have, Mr. Snelson, explicit values for these benefits associated with proceeding with Mattagami?

MR. SNELSON: A. What do you mean by --

Q. In terms of present -- I'm sorry, do you have explicit present value numbers?

A. No.

Q. Maybe I can ask you the question this way or ask you a further question in respect to that.

At what present value -- and I'm now thinking in terms of table 1.1, which might be the easiest way to do it, just taking table 1-1 as a benchmark.

At what present value number would

Ontario Hydro decide that the deferral of the Mattagami complex would be justified, putting it in the terms of table 1-1?

A. I don't think it is as simple as a matter as that, that there is a defined value where it is more than that value you cancel the project and if it is -- or defer the project, and if it is less than the value you go ahead.

Q. Can it be done in terms of a range, a range of values?

A. I believe that the judgment to go ahead is the balancing of a range of complex matters and that the judgment has been made on the basis of the current information to go ahead.

I would have a great deal of difficulty trying to, and I don't think I should even attempt to, speculate as to what sort of judgments might be made in a variety of hypothetical situations.

So I really can't speculate other than based on the current information. On the current information the decision was to go ahead.

Q. Well, let's keep the discussion in general terms.

What criteria are used by Ontario Hydro and were used by Ontario Hydro in this case in making

decisions concerning deferral of certain resource options and not deferring others?

A. A whole range of matters were considered, and you see in attachments A and B, which are the September and October board memos, the specific ones that were addressed in discussions with the board.

Q. Now, let's return to page 11, if we could, of 796.

You may have already answered this, but I'm looking at the last bulleted item on page 11 where you indicate that the hydraulic cost/benefit ratios discussed by Panel 10 and the economics of deferral are all based on a March, 1992 system incremental costs, which are to be found in Exhibit 592, and that more recent system incremental costs issued in November of 1992 would tend to reduce the long-term benefits of hydraulic options by 10 per cent.

Has Hydro done new calculations which include the November, 1992 system incremental costs?

A. What specific new calculations are you referring to? We have not done new cost/benefit ratios for hydraulic projects. I said that in my direct evidence.

Q. Yes, I recall that.

Now, could I ask you to turn to

attachment D and on page 2 -- and let me know when you are there. You are discussing -- sorry, you're not there. Are you? All right.

You are discussing on this page the issue of incremental system values and changes that were made with respect to them.

Can you indicate for me, Mr. Snelson, if you are the right witness, what value if any would be applied to interarea transmission through the Mattagami project?

A. I'm afraid I can't recall what assumptions were made about interarea transmission credits for hydraulic projects. It was discussed by Ms. Basu-Roy on Panel 6 in terms of the evaluation of cost/benefit ratios. That same methodology was used to update the tables for Panel 10, and, as I've said, there have been no new calculation made since then.

Q. Now, we had discussed a moment ago in connection with page 11 of this exhibit, 796, the 10 per cent decrease in the long term benefits of hydraulic options.

Can you tell us, Mr. Snelson, how much of this drop or decrease is attributable to a change in the value of transmission and how much is due to the change in the value of generation?

A. If you turn to -- I believe it is mostly due to generation. The basis for that statement is the figure on page 11 of attachment D, which I believe excludes transmission.

Q. That being figure 2?

A. That's correct.

Q. I'll come back to that. Could I ask you to turn to attachment G? And we will be looking at figure 6-1 on page 15.

THE CHAIRMAN: I'm sorry, which document is this?

MR. CASTRILLI: I'm sorry, Mr. Chairman. It is attachment G of Exhibit 796.

THE CHAIRMAN: G as in George?

MR. CASTRILLI: G as in George, yes.

[2:45 p.m.]

Q. This figure is a summary of surplus management and capital project impacts on electricity prices. Mr. Snelson, does Hydro estimate what the expected rate impacts would be of deferral or cancellation of the Mattagami Complex?

MR. DALZIEL: A. The answer is no, not individually for the Mattagami project.

Q. Still with this exhibit, you provide in this figure 6-1 the value of the output of various

supply side and demand side resources based on, for example, fuel costs of 30 megawatts per hour for low sulphur coal. Did you provide a valuation for capacity as opposed to energy?

A. The valuation of capacity, OM&A and fuel costs were all taken into account in estimating the rate impacts. An example of that is shown in table 5-1, page 14. Those kinds of capital reductions were taken into account in considering demand management and the hydraulic, environmental controls, the other options that involve capital.

The fueling costs that were used I guess are the ones that are indicated in the table. What we are looking at is the cost associated with the energy in table 6-1, so that does not include an allowance for capital, if that is getting to the answer to your question. But was capital included in the evaluation, the answer is yes.

Q. So as I have it, the $30 per megawatthour represents a value relating only to energy in figure 6-1?

A. That is my understanding.

Q. Now, could I ask you to turn to attachment H, schedule 4, of that attachment. In this particular attachment in this particular schedule,

under the heading of hydraulic we see the last item listed is a reference to the Spruce Falls power update, and unlike the most of the other -- or I believe all of the other hydraulic projects listed in schedule 4, there is not a narrative relating to this project contained in schedule 1 of the same attachment that I could find. Could you identify and describe this project, first of all, and explain why it's included in schedule 4, and also tell us the basis for the data that's provided in schedule 4 in relation to it?

A. I don't think any of us here have the specifics as to what that is referring to. It may have something to do with the arrangements in regard to the payment for power to Spruce Falls Paper that is part of the agreement surrounding Mattagami, but the specific details I don't think any of us here have them.

You will notice that in total it's a very small item, and that if you look at the column of the figures, it's a question of shifting of it in time, that you have a number of positive and negative numbers that almost counterbalance. So it's a shifting of some payments around in time, that have little impact.

Q. Exactly how much in the way of payments are we talking about in terms of shifting. Is it in the quarter billion dollar range?

A. I am afraid I don't know.

Q. Gentlemen, if you will bear with me, this next question relates in part to other exhibits which I don't have in front of me. I am just going to quote some numbers from them and over the evening you can review those exhibits and numbers subject to check. Not a great deal turns on the fact that these numbers appear in different places, except that they are not always the same number.

Since 1989, as I understand it, the Niagara project has been considered at a variety of capacity ratings, and the information we have is that in the DSP itself Niagara is listed at 550 megawatts, that's to be found at page 3?

A. That's Exhibit 3?

Q. I believe it's Exhibit 3, yes. While in the DSP Update it's shown has 600 megawatts. That would be Exhibit 452, page 22. I believe that same figure of 600 megawatts is what you include in what is now attachment G to Exhibit 796, at page 6.

Yes, you will see a figure of 600 megawatts on page 6 of attachment G with respect to Niagara.

Now the reason why I want to just provide with you that background is I wanted to understand a

figure that appears in attachment J of Exhibit 796, and we are looking table A-1-2. Let me know when you have that table.

A. We have it in front of us.

Q. Now this table, the item I am looking at in connection with table A-1-2 is a figure of 921 megawatts for a line item entitled uncommitted hydraulic in the year 2002.

A. Yes.

Q. Now is that, some or all of that, in relation to Niagara?

A. All of that is related to Niagara, as is another number further down in the column.

Q. That would be minus 321?

A. That's correct.

Q. For years uprated or downrated?

A. Yes.

Q. What I wanted to understand -- and that's in megawatts for the same year. Now what I want to understand is does that imply -- I take it that implies that the Niagara project could be expanded beyond 600 megawatts all the way up to 920 megawatts; is that a fair assessment?

A. Yes.

Q. Has Hydro compared the

cost-effectiveness of expanding Niagara to 900 megawatts versus proceeding with Mattagami, or indeed doing other comparisons with resource options?

A. What is being indicated in that table is a net capacity addition of 600 megawatts, and that is associated with the Niagara development. The 921 is entered in one place and an adjustment is made lower down in the table, so that when the return is done and when the capacity balances are done, effectively 600 megawatts have been added in that year associated with the Niagara project.

MR. B. CAMPBELL: Mr. Chairman, again on Panel 6 my recollection is that there was explicit discussion of the fact that this project, depending on the number of units that were installed at Niagara, it was contemplated that over time the analysis, or that there were options in terms of the number of units that could be put in at Niagara and that explained this range. I believe this has all been discussed in Panel 6.

MR. CASTRILLI: Mr. Chairman, it's almost three o'clock. I do have a bit more. This is probably an appropriate place to stop.

THE CHAIRMAN: We will stop now and continue tomorrow morning at nine o'clock. I remind

you once more that we will not be sitting on Thursday this week.

THE REGISTRAR: Please come to order. This hearing is adjourned until nine o'clock tomorrow morning.

---Whereupon the hearing was adjourned at 2:58 p.m., to be resumed on Wednesday, January 6, 1993, at 9:00 a.m.

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